General Transformer Design

For normal life expectancy, transformers are assumed to be continuously loaded at rated kilo-volt amperes and rated voltage. In addition, the average temperature of the cooling air during any 24-hour period must be ≤ to 30 C and must not exceed 40 C with the transformer installed at a maximum elevation of 1000 m. For dry-type transformers operating under these conditions the hottest-spot temperature of the winding is assumed to be 140 C for transformers with Class 150 C insulation; 175 C for transformers with Class 185 C insulation and 210 C for transformers with Class 220 C insulation. The hottest-spot temperature of the winding is the sum of the ambient temperature, the average temperature rise over ambient of the winding conductor , and the hottest spot allowance. The hottest-spot temperature of the winding is limited to 10 degrees C less than the winding temperature class to allow for differences in measured and actual temperature. Operated under these condition, transformers are designed to have a normal life expectancy of 20 years.[1]

Although transformers can be manufactured with different temperature classes , in general, modern dry-type transformers, larger than 30 kVA, are designed with UL component recognized 220 C insulation systems. The standard temperature rise for such transformers is 150 C. However high-efficiency low-loss dry-type transformers can be specified with an 80 C or 115 C temperature rise to provide greater overload capability and longer life than an 150 C rise transformer. A 115 C rise transformer has approximately 10 times the life and a 15% overload capability compared to a 150 C rise transformer. An 80 C rise transformer has a 30% overload capability.[2]

The temperature sensitivity of organic insulation material gives rise to the "ten degree rule" for extrapolating life expectancy. This rule states each 10 degree increase in temperature decreases insulation life in half. Conversely each 10 degree reduction in temperature doubles life expectancy. This rule can be expressed mathematically by:

$$L_{new} = 2^{\frac{\Delta T}{10}} * L_{design}$$

ΔT= Winding temperature (design) - Winding temperature (actual)
L = Equipment Life

Specified Cooling Tower Transformer Design

The cooling tower secondary unit substation (SUS) transformers were originally specified to be rated 2500 kVA self-cooled (AA) / 3750 kVA fan-cooled (FA) with an 80 C temperature rise.[3]

The self-cooled rating of the transformer was based on the maximum horsepower rating for twelve fans and auxiliary power requirements. According to Black & Veatch's design calculations the maximum load at the cooling towers, with one transformer in service for each cooling tower was 2515 kVA (2065 kVA of running motor load and 450 kVA maximum auxiliary power load for one cooling tower). This rating essentially matched the self-cooled transformer rating of 2500 kVA. The force-cooled rating, 3750 kVA, was 150% of the self-cooled rating. This rating allowed 18 of the 24 fans to be in service at the full 200 HP nameplate condition with one transformer out of service.

A more rigorous analysis of the transformer design ratings indicates the self-cooled rating is capable of providing of 88% of the maximum fan horsepower design.

$$kVA_{fan} = \frac{(Number\ of\ Fans)*(Fan\ Motor\ HP)*(Service\ factor)*(746\ Watts/HP)}{(\eta)\ *\ (pf)}$$

$$= \frac{12\ Fans\ *\ 200\ HP/Fan\ *\ 1.15\ SF\ *\ 0.746\ kW/HP}{(.959)\ *\ (0.90)}$$

$$= 2{,}386\ kVA$$

$$kVA_{system} = kVA_{fan} + kVA_{max\ aux\ load}$$

$$= 2{,}386\ kVA + 450\ kVA$$

$$= 2{,}836\ kVA$$

The fan-cooled rating of the transformer was based on 150% of the self-cooled rating. This rating provides equipment redundancy by providing the ability to supply both cooling towers if a SUS transformers or the SUS main circuit breaker fails. With a rating of 3750 kVA the SUS transformer could have supplied all 24 fan motors, at reduced load, and the normal auxiliary power of both towers . Maximum design auxiliary power requirements were 450 kVA for SUS 1(2)A11 and 175 kVA for SUS 1(2)B11. Based on these assumptions the capacity of the specified transformer rating are shown.

$$HP_{fan} = \frac{(kVA_{system} - kVA_{aux\ load})\ *\ (\eta)\ *\ (pf)}{(Number\ of\ fans)\ *\ (.746\ kW/HP)}$$

$$= \frac{(3750\ kVA - 625\ kVA)\ *\ (.958)\ *\ (0.90)}{(24)\ *\ (.746\ kW/HP)}$$

$$= 150\ HP$$

Based on the original design a single transformer could supply all 24 fans if they were not operated above 150 horsepower each.

The original design was very conservative because it specified a low transformer temperature rise (with corresponding life and overload capability) while still allowing almost full fan motor capacity under normal conditions.

Actual Cooling Tower Transformer Design

However the transformers, as manufactured by Square D, failed factory testing and could not meet the original specifications. Square D proposed re-rating the transformers to 2200 kVA (AA)/ 3100 kVA (FA) with an 80 C rise.[4] Based on the re-rating by the transformer manufacturer, the fan motors are limited to 169 horsepower for one transformer supplying one cooling tower.

$$HP_{fan} = \frac{(kVA_{system} - kVA_{aux\ load}) * (\eta) * (pf)}{(Number\ of\ fans) * (.746\ kW/HP)}$$

$$= \frac{(2200\ kVA - 450\ kVA) * (.958) * (0.90)}{(12) * (.746\ kW/HP)}$$

$$= 169\ HP$$

According to the original design constraints, with one transformer supplying both cooling towers the motor horsepower limit is 119 horsepower.

$$HP_{fan} = \frac{(kVA_{system} - kVA_{aux\ load}) * (\eta) * (pf)}{(Number\ of\ fans) * (.746\ kW/HP)}$$

$$= \frac{(3100\ kVA - 625\ kVA) * (.958) * (0.90)}{(24) * (.746\ kW/HP)}$$

$$= 119\ HP$$

However, the nameplates on the Unit 2 SUS transformers indicate a 2500 kVA self-cooled (AA) / 3750 kVA fan-cooled (FA) rating with an 80 C temperature rise on the high voltage coil and an

89 C temperature rise on the low voltage coil. Using the low voltage coil as the limiting factor results in a self-cooled rating of 2372 kVA with an 80 C temperature rise. At this rating a single transformer can supply one cooling tower with the motors at 185 horsepower.

Assuming a constant ratio of fan-cooled to self-cooled (FA/AA) as originally given in the manufacturers re-rate results in fan-cooled rating of 3342 kVA. This rating is essentially equal to the rating of 3350 kVA used in the report entitled *"Project Modification (PM) No. 273 Report on Options for Providing Redundant Power to Cooling Towers".*

Based on this rating, one transformer can safely supply both cooling towers with a maximum motor load of 131 horsepower. The cooling tower fans can be adjusted to this level without removing any of the significant thermal margin originally designed in to the transformers.

Transformer Loading Optimization

The original design criteria provided significant margin. The transformer manufacturer, Square D, has verbally confirmed that these transformers are at least a 185 C insulation class and probably are 220 C insulation class. Assuming a 185 C insulation class, these transformers may be loaded above their nameplate rating, for any period of time, with normal life expectancy provided that the 24-hour average temperature hottest-spot temperature of 175 C is not exceeded. For calculating loads with normal life expectancy ANSI/IEEE C57.96-1989 recommends using the average temperature over a period of years for the month involved. [5] Based on meteorological data and using the highest monthly average (July) this results in an average monthly temperature of 24.6 C. [6]

For 185 C insulation system transformers the life expectancy is defined by

$$\log_{10}(LIFE) = 5907/T - 7.941$$

T = hottest spot temperature (K)
Life in hours

Under the existing loading criteria of 131 horsepower this results in a expected life of over a million hours. If we limit the temperature rise to 120 C this results in a life expectancy of

$$\log_{10}(LIFE) = 5907/T - 7.941$$

$$= \frac{5907}{(24.6 + 80 + 273)} - 7.941$$

$$= 7.7$$

$$LIFE = 10^{7.7}$$

$$= 50{,}412{,}489\ hours$$

$$= 5750\ years$$

assuming a maximum average daily temperature of 30 C, with a 10 C hottest spot allowance and an 80 C rise results in a 120 C hottest spot temperature. There is a 55 C temperature rise margin for additional loading. This equates to approximately 19% extra capacity.

The maximum design auxiliary load at the cooling towers was calculated at 625 kVA. According to the PM 273 study, the load is actually closer to 400 kVA. This allows fan operation at 173 HP.

$$HP_{fan} = \frac{(kVA_{system} - kVA_{aux\ load}) * (\eta) * (pf)}{(Number\ of\ fans) * (.746\ kW/HP)}$$

$$= \frac{(4000\ kVA - 400\ kVA) * (.958) * (0.90)}{(24) * (.746\ kW/HP)}$$

$$= 173\ HP$$

Unit 2 Generator Step-Up Transformer Modification, Maintenance & Repair
February through April 2004

Summary

During the Unit 2 Spring 2004 Outage, work on the generator step-up transformer included installing new oil coolers to increase the transformer oil cooling capability, modifying the isolated phase bus enclosure and repairing transformer components to correct oil leaks. The isolated phase bus modifications required removing and re-installing all three transformer low side bushings. Because previous offline testing (Unit 2 GSU Doble Test Summary) and the continuous bushing monitoring system indicated increasing degradation of the X3 bushing. This bushing was scheduled for replacement during the outage.

At the beginning of the outage, a baseline Doble (power factor) test was performed on the entire transformer and all of the individual transformer bushings. In addition, the three low side bushings were Doble tested after they were removed from the transformer. Based on the results of these tests and a visual inspection of the bushings it was decided to replace the X3 bushing because of failing insulation and the X1 bushing because of a slight oil leak at the capacitance test tap.

Two bushings, previously rebuilt by LAPP, were drawn out of the warehouse and Doble tested to verify the bushing condition before installation in the transformer. After the transformer was filled with oil, the entire transformer and each individual bushing were once again Doble tested. All test results were acceptable.

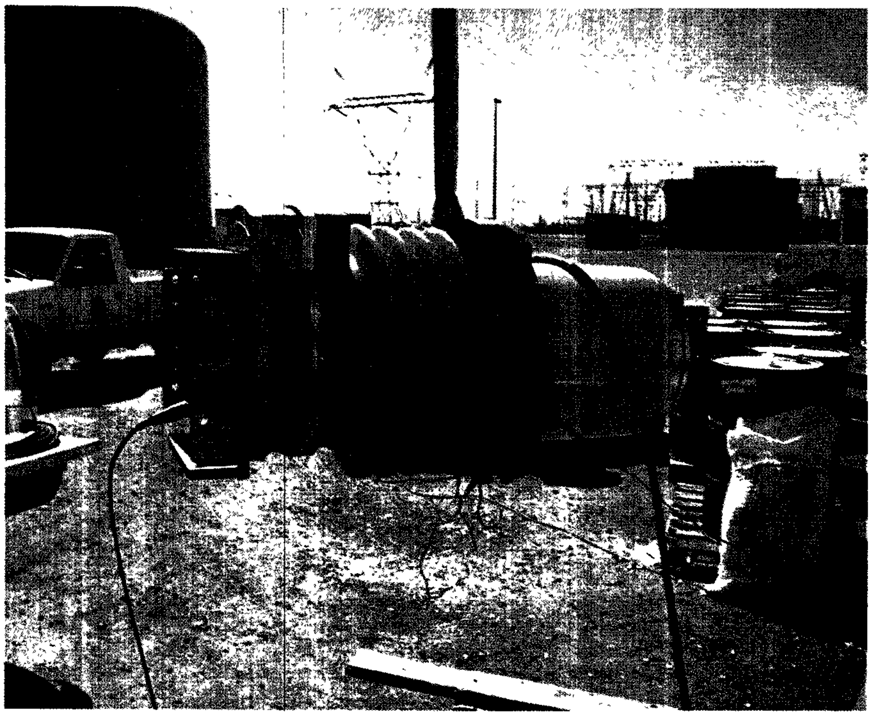

Figure 1 -Doble test of removed bushing

On March 30, three days after the transformer was re-energized, the continuous bushing monitoring system indicated a problem with the X1 bushing. The transformer was removed from service on April 3 and measurements taken at the monitoring system and bushing indicated the X1 bushing was grounded internally in the bushing test tap.

All three low side bushings were once again Doble tested. The X1 bushing tripped the test set because of the ground connection, the X2 bushing tested normally and the X3 bushing had a step change in capacitance. The X3 bushing was replaced with the last spare bushing from the warehouse. This bushing had been repaired by ABB in 1991. The original X1 bushing , removed because of a slight oil leak, was reinstalled. Each bushing was tested before installation and after it was re-installed in the transformer. All tests were satisfactory.

The transformer was returned to service on April 8, 2004 and the failed bushings were sent off for repair and analysis.

<u>Detailed Analysis</u>

The X3 bushing, replaced because of failing insulation, was an original bushing, manufactured by GE. It was sent to ABB for analysis and repair. ABB is now the original equipment manufacturer for this equipment through their purchase of Westinghouse's bushing division who had acquired GE's transformer and bushing group.

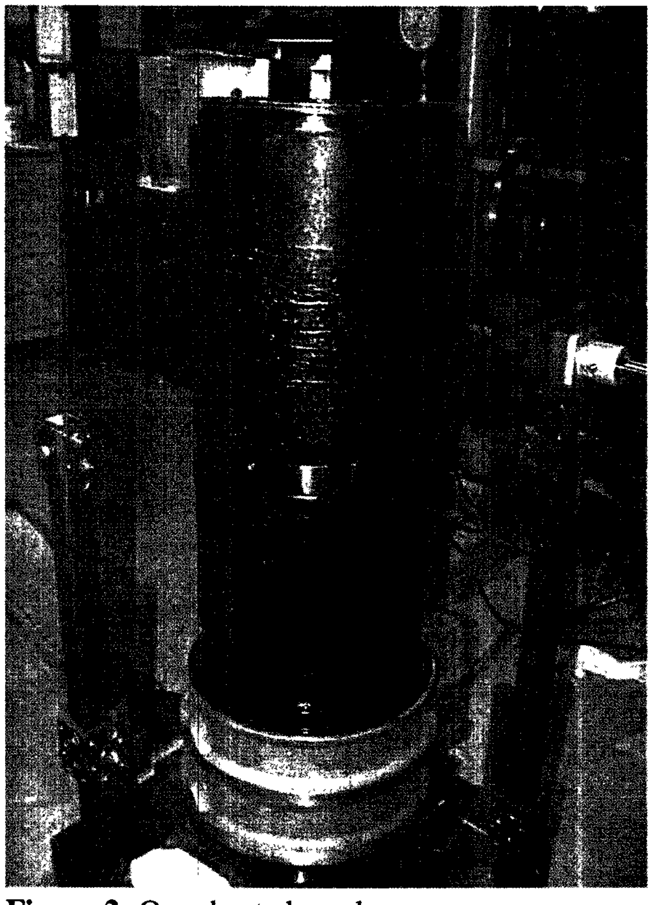

Figure 2- Over heated condenser

ABB has repaired and returned this bushing. They are still in the process of preparing their report, but the preliminary results indicate this bushing failed because of overheating. Once the oil overheated it etched the inside of the porcelain and caused the gaskets to fail and allow the oil to drip out. When this bushing was removed from service it contained 3 quarts of oil instead of the specified 4.6 gallons.

As part of the repair, the bushing conductor was replaced because ABB could not remove the conductor from the terminal. In addition, ABB opened up and smoothed out the rough casting in the test tap area because they felt it was too small..

The bushing is now back on site.

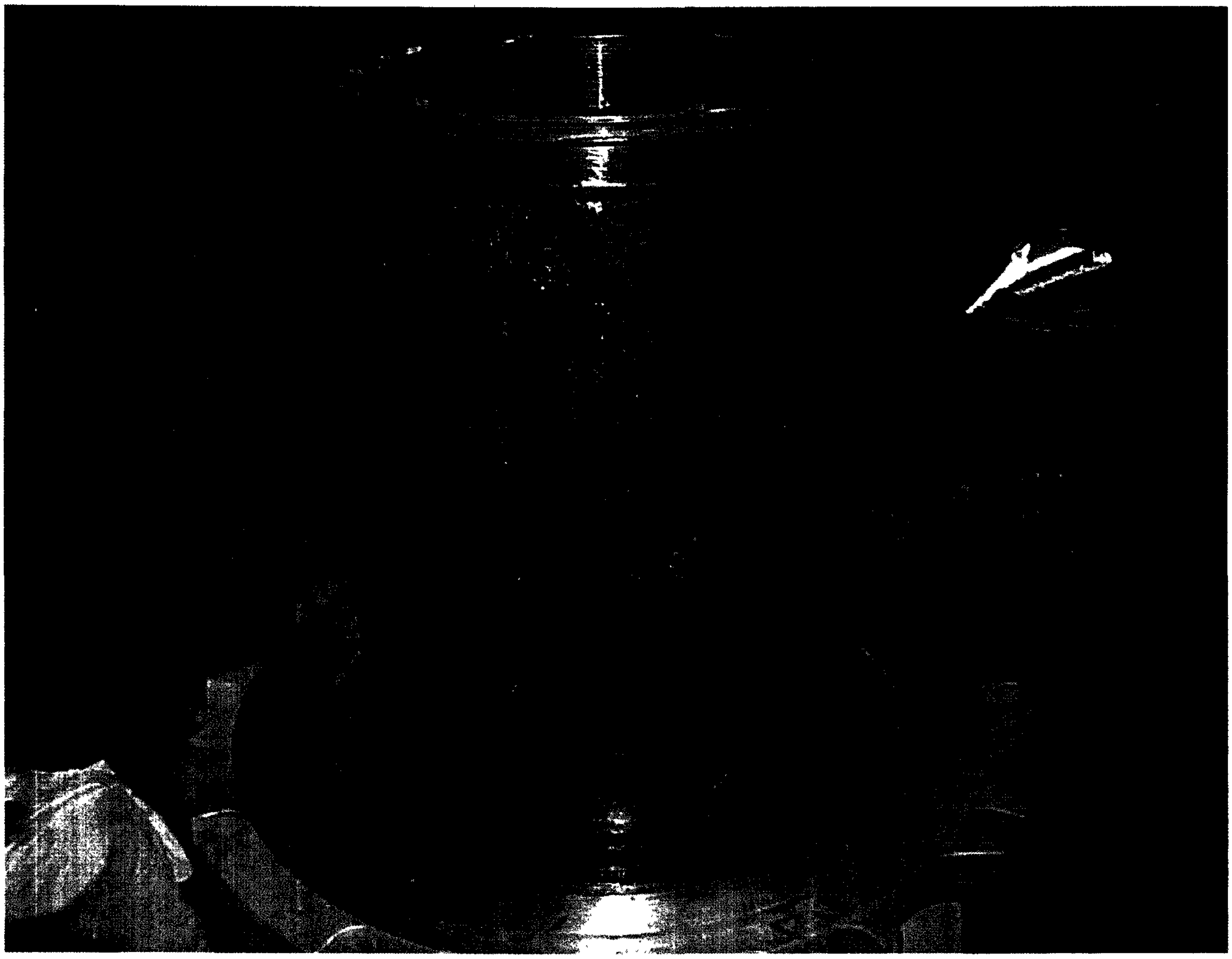

Figure 3- Close up of failed bushing condenser

The X1 bushing removed from service on April 3, 2004 was sent to LAPP Insulator Company. This bushing was rebuilt by LAPP in December 2000. LAPP concluded a piece of metal in the bushing shorted the tap. In addition, they noted a slight burn mark in the test tap area .

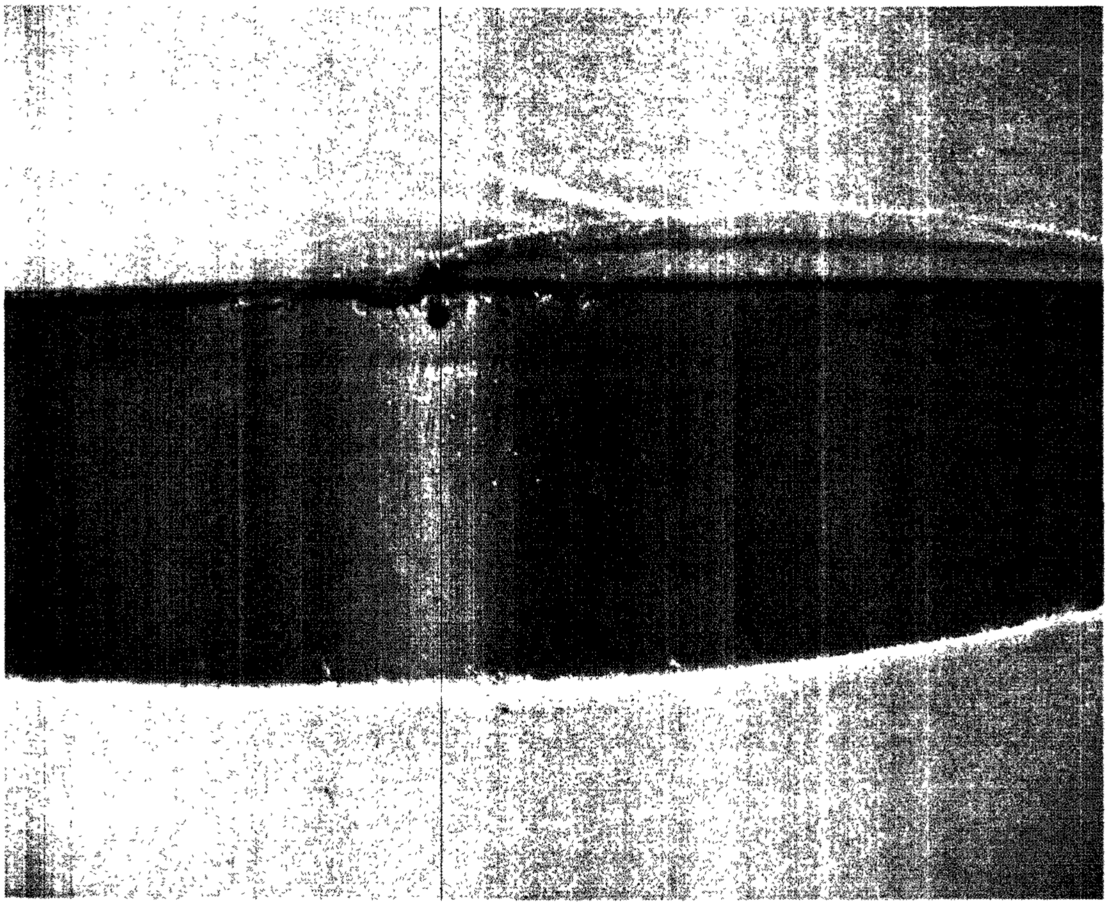

Figure 4-X1 bushing burn mark

They repaired the bushing by opening up the area in the cast area for the test tap. It is now back on site. LAPP did not charge for the analysis or repair even though their standard warranty is 12 months, from shipment on repaired bushings.

A copy of the complete analysis from LAPP is attached.

The X3 bushing removed from service on April 3, 2004 was sent to ABB. The gaskets and seals were replaced by LAPP in February 2003.

This bushing was removed because the C_2 capacitance had increased 28% since it had been installed. This increase was similar to the increase in the X1 bushing before it became grounded. The bushing was sent to ABB for repair and analysis. ABB indicated that although the bushing did not have any noticeable problems, the increase in the C_2 capacitance and the very low value of the C_1 capacitance was cause for concern. In addition, they were concerned with the number of spacers in the bushing and the layout of the insulating material.

This bushing was completely rebuilt by ABB, including replacing the conductor, and it is now back on site.

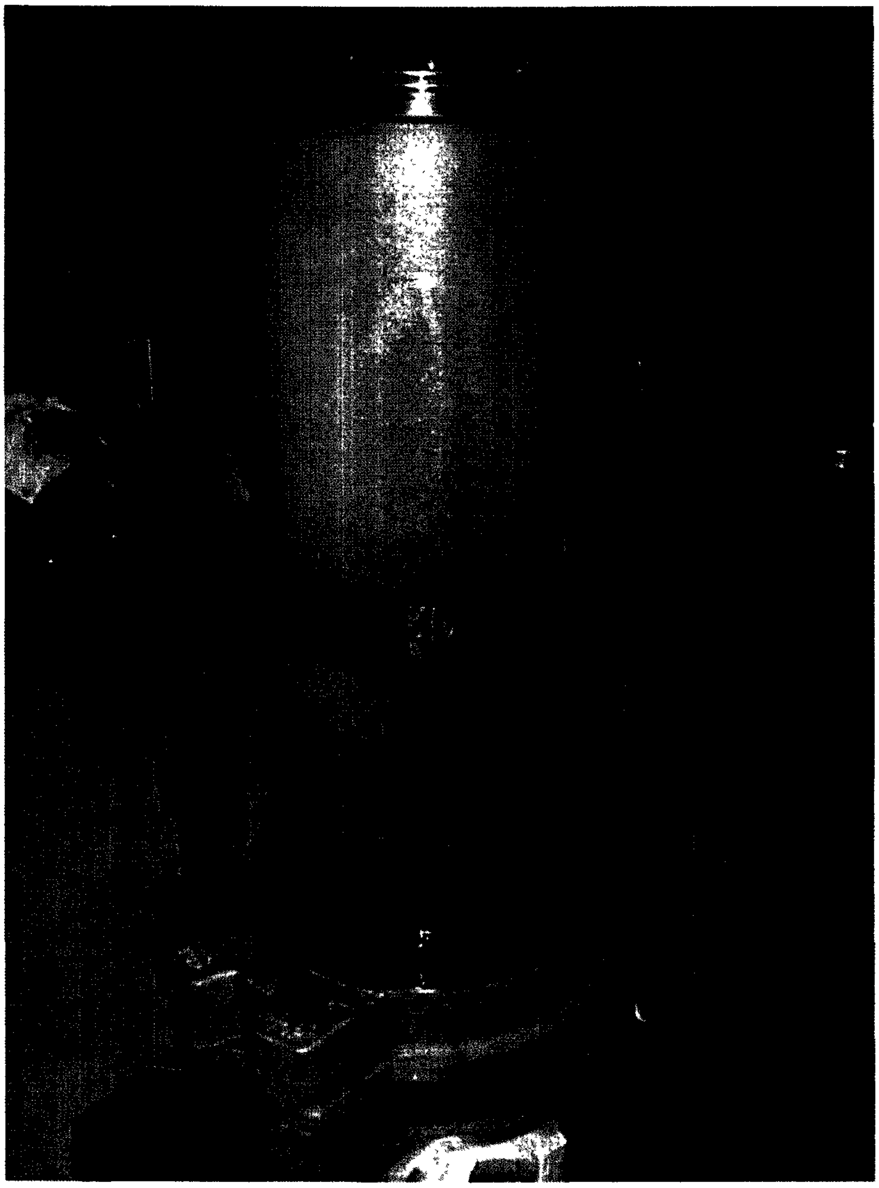

Figure 5-X3 Bushing condenser (no evidence of overheating)

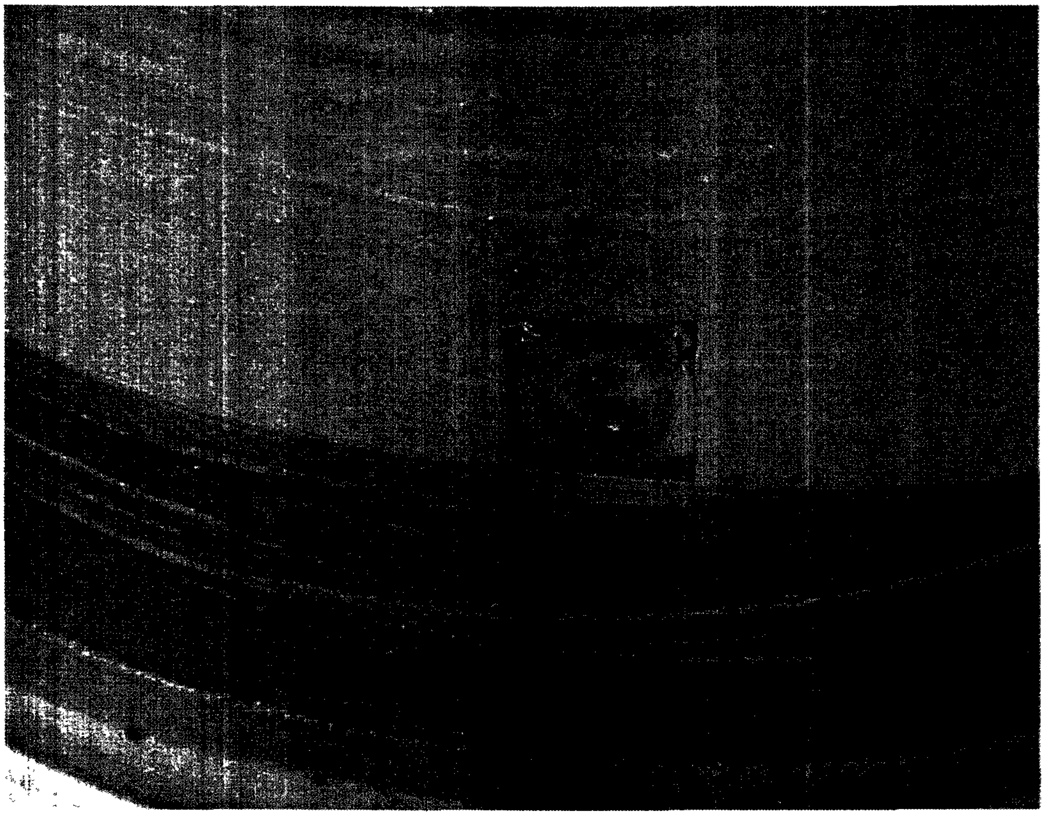

Figure 6-X3 Bushing showing bandage

Unit 2 Turbine-Generator Testing April 11, 2002
Electrical System Observations/Comments

GENERATING STATION REACTIVE POWER CAPABILITY

Observations/Comments

During the test, the Unit 1 generator was used to provide VAR support while the Unit 2 generator was held close to unity power factor. This was done to insure the Unit 2 generator was operated within its capability curve. Unit 2 provided between 15 MVAR lagging to 30 MVAR leading while Unit 1 provided between 240 to 340 MVAR lagging. These reactive power measurements were made at the terminals of the respective generators.

During testing the generator reactive power measurements were compared to reactive power readings at the Converter Station. When Unit 1 indicated 300 MVAR lagging the Converter Station indicated -92 MVAR. When Unit 2 indicated 4 MVAR lagging the Converter Station indicated 195 MVAR. The Generating Station shows reactive power as leading or lagging at the terminal of the generator, while the Converter Station references reactive power to the Intermountain Switchyard. Reactive power into the switchyard is negative while reactive power out of the switchyard is positive. These reading indicate a 200 MVAR offset from the Generating Station readings to Converter Station readings. Part of the discrepancy is caused by the reactive power required by the generator step-transformer, auxiliary transformers, tieline and the 6900 volt loads. The other part appears to be a calibration error in the Converter Station metering.

As a check of the metering, we also compared the power readings from the output of the generator to the power input , as shown by Converter Station instrumentation. When the auxiliary power, used at the generating station, is subtracted from the output of generator the power measurements are accurate at levels below 900 MW. The Converter Station instrumentation is currently set to indicate a maximum level of 900 MW from the generators.

Initial testing indicates there is adequate reactive power support at the Intermountain Power Project to support both generators operating at 950 MWg with existing equipment. Operating at these power levels may require changes to the existing operating philosophy in both the generating station and converter station.

During the Unit 2 test the Converter Station operated with all three filter banks in service but with only one shunt reactor in service. Each filter bank can provide a maximum of 297 MVAR into the switchyard. A shunt reactor provides 90 MVAR out of the switchyard. During the test, AC Filter Bank 1 provided 207 MVAR while AC Filter Banks 2 & 3 each provided 297 MVAR. Using the other shunt reactors would reduce reactive power requirements from the generators and would have provided some voltage support to the AC Switchyard. The switchyard bus voltage did drop 4 to 5 kV during the test.

When the generator is operating at 950 MW it is capable of providing 280 MVAR lagging. During the test, the power output from the generating station was held constant by lowering the Unit 1 output while Unit 2 was raised. The peak reactive power contribution from the generating station was 370 MVAR. This leaves 190 MVAR capability from the generator which can be used with the 180 MVAR from the Converter Station Filter Banks to provide voltage support.

There was a slight increase in reactive active power requirements for both Mona lines during the test. Both lines show an increase of 6 to 8 MVAR out of the switchyard.

Recommendations

The Converter Station uses an automated system to determine which filters must be placed in service for various operating loads. This system should be reviewed, and modified if necessary, to insure that a shunt reactor can be placed in service whenever a majority of the individual filters are put any service for any filter bank. When the generating station is operating, with both generators on line, at outputs above 875 MWg, a shunt reactor should be placed in service with each filter bank unless the switchyard voltages limits adding the reactor. As a general rule the shunt reactors should be used to provide voltage support while using the generators to “fine tune” the switchyard voltage.

The Converter Station metering should be adjusted for a maximum generator output of 1200 MW so the normal readings are more within the scale of the instrumentation. The metering should also be calibrated to provide an accurate comparison between the Generating Station and the Converter Station.

In order to make an accurate comparison of the reactive power var transducers should be added to the IGS auxiliary buses. The analog var meters should be replaced or calibrated to remove the discrepancy between the recorders, TGSI system and meters in the IGS control room.

After the above recommendations have been completed we should perform a test at various power and reactive power loads to determine the actual operating conditions.

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: S. Gale Chapman

FROM: Dennis K. Killian

DATE: October 7, 1996

SUBJECT: Energy Efficiency Improvements for Administration Building

Our review of the Administration Building Lighting and HVAC System (Cost Savings Idea #27) indicates that it is economically feasible to modify the existing HVAC system. These modifications would require a capital outlay of $2,200 and result in a present worth savings of $21,000. We recommend implementing these modifications.

Our review indicates it is not economical to modify the existing lighting system. The original design of the Administration Building included several efficiency improvements such as energy efficient lamps/ballasts and time control of office lighting. Currently available technology will not significantly reduce energy consumption without excessive cost. Our analysis of the Administration Building Lighting and HVAC System is included for your review.

I f you have any questions or require additional information please contact Gordon Bigham (6483) or Jon P. Christensen (6481).

JPC/JHN

Enclosures

Administration Building Lighting System Energy Analysis

Design

The total electrical load for lighting in the Administration Building is ≈ 81 kW. To reduce energy consumption, the original design of the Administration Building used a master clock in connection with a low voltage control scheme to switch lights in offices, cubicles and conference room. Currently this system switches ≈ 61 kW. The load on this system is summarized in Table 1.

Zone 1 First Floor				
Fixture Type	Quantity	Number of Lamps	Lamp Watts	Total Watts[1]
AH3G	129	3	34	14,474
AH2G	18	2	34	1,346
RS	34	1	70	2,618
Zone 2 Second Floor				
Fixture Type	Quantity	Number of Lamps	Lamp Watts	Total Watts[1]
A2GAX	196	3	34	21,991
A2GX	225	2	34	16,830
A#G	12	3	34	1,346
RS	34	1	70	2,618

Notes:
1. $\textit{Total Power} = \dfrac{\textit{Number of Fixtures} \times \textit{number of lamps} \times \textit{lamps wattage}}{\textit{fixture efficiency}}$

In order to reduce energy use in areas not currently controlled by the master time clock occupancy sensors or timers could be installed to control the lights. This approach would require modifying the existing switches and installing additional equipment. Because the existing non-controlled lighting is in closets, storage rooms, mechanical equipment rooms and similar installations this approach would not significantly reduce energy use and is not economically feasible.

Based on $0.012/kWh the cost of power for timed circuits in the Administration Building is

≈$6300 per year, if the circuits are energized 24 hours per day. The existing control system switches the lights on at 6:00 am and shuts the lights off at 12:00 midnight on Monday through Friday. At all other times the lights are switched off but all the lights on an entire floor can be turned on through the use of a master switch. Or lights in individual areas can be turned on through the use of zone switches in the lighting control cabinets. The current time control system reduces the light use to 90 hours per week or 4,680 hours per year. This results in a savings of $2,930 per year.

Further reductions are possible by changing the lighting off-time to 7:00 pm and not turning the lights on during holidays. This would require re-programing the existing time clock every year and having personnel working in the building outside of normal work hours (i.e. janitorial staff) use the existing overrides. Reprogramming would requires approximately 1 hour or $25 labor. This plan would save an additional $1,420 per year.

Since actual savings would probable be considerable less due to light requirements for janitorial work and other personnel working outside of normal hours we do not recommend making this change or any other modifications to the current system.

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: S. Gale Chapman

FROM: Dennis K. Killian

DATE: May 14, 1993

SUBJECT: Air Compressor Motor Analysis

FILE: 01.12.02, 43.1801

Our review of the recent problems associated with the operation of the D air compressor motor indicates this motor should be sent to a factory authorized repair facility. We recommend the motor be sent to Westinghouse (Houston, Texas)for a thorough examination and repair.

After discussing the problems we are having with this motor with Westinghouse Large Motor Service we have identified the following repair/replacement options.

1. Purchase a new identical motor from Westinghouse. This would be a custom motor which would require retooling by Westinghouse because they no longer manufacture this model of motor. This motor would cost over $100,000 and would require a year for delivery.

2. Purchase a new identical motor from Bob Green Electric. This motor is supposedly built from the original Westinghouse specifications by a Mexican Company. We have some concerns about quality but this alternative could be investigated further if repair is not a viable option. Bob Green has quoted $29,370 for a new IEM motor with a 14 week delivery.

3. Purchase a mechanically and electrically identical motor. This would provide us with a more efficient design but would require stocking different bearings and renewal parts because they would not match the other three air compressor motors. Westinghouse has quoted $45,000 to $60,000 for this motor with a 21 week delivery. The range in prices covers the amount of modifications we would have to make to the air compressor skid for mounting.

4. Send the motor to another repair shop for examination and possible repair. Westinghouse recommends Eastern Electric in Salt Lake City or the Westinghouse Shop in Houston, Texas.

a. Repair at Eastern Electric does not appear to be a viable option because of our previous experience at this repair shop.

b. Repair at Westinghouse in Houston. This option would provide a repair facility with direct access to the original motor manufacturer and would provide maximum capability for a thorough and acceptable repair. The repair shop has estimated $17,000 for replacement of the shaft and testing with an estimated two week turn around. They will be able to give us a firm price after they examine the motor.

5. Purchase a used motor. Bob Green has quoted $33,000 for rewinding an existing Westinghouse motor identical to our existing motors. They estimate 3 weeks for delivery. This motor is only available until June 28, 1993.

SUMMARY

Option	Cost	Delivery	Comments
Purchase identical motor (Westinghouse)	$100,000	52 weeks	Custom built. Westinghouse no longer manufactures this motor.
Purchase identical motor (IEM)	$ 29,370	14 weeks	Built by a Mexican Manufacturer to original Westinghouse Specifications.
Purchase a mechanically and electrically duplicate motor.	$ 60,000	21 weeks	Price may be reduced if we modify the air compressor mounting skid. Based on a Westinghouse motor.
Repair existing motor.	$ 17,000	2 weeks	Price based on shaft replacement. Firm price requires motor inspection.
Purchase used motor.	$ 33,000	3 weeks	Bob Green will purchase a used motor and have it rewound to our specifications.

FAX sent to Sandra (Westinghouse) 4/22/93
Facsimile phone: 512-388-0320

The Intermountain Power Project has four Westinghouse 700 HP induction motors used as drivers for Elliot Air Compressors. We would appreciate your providing us with technical assistance on the design and operation of the sleeve type bearings for these motors. And for providing information regarding the possibility of additional filtering of the motor cooling air.

The nameplate data on these motors follows:

HP: 700	FLA: 53	MOUNTING: Horizontal
RPM:3582	LRA:384	ASSY: F-1
POLES:2	KVA CODE: G	BEARINGS: Split Sleeve
FRAME: LLD	ENCL: D.G.	DUTY: Continuous
VOLTAGE: 6600	S.F.: 1.0	Stator RTD: 100 ohm
Phase: 3	Ambient/Rise: 40/80 C	End Play: .50 inch min.

These motors were purchased by Elliot Co under Westinghouse Shop Order number S.O. 82F52938.

We recently lost an inboard bearing on one of these motors due to loss of the lubricating oil. The motor ran for approximately four hours with minimal oil . This caused the bearing to reach temperatures in excess of 260 F and resulted in the total destruction of the bearing and oil seal. In addition, there was some shaft damage.

We had a local motor repair shop skim cut the damaged portion of the shaft, build the shaft back up by welding and then re-machine the shaft. The damaged bearing was replaced and the oil seal rebuilt. When we put the motor back in service the vibration on the motor was significantly higher than before the failure.

There has been a significant increase in the axial vibration at 3X running speed and in horizontal and vertical vibration at 1X and 2X. Please provide us with your recommended bearing fits (bearing to shaft and bearing to housing) and with information about the setting of the motor shaft comparing mechanical center to magnetic center.

In addition, please provide us with any available information regarding the addition of air filters to these motors. The air compressors are continually leaking oil which is coating the windings of these motors. We would like to add external disposable or mesh type filters which can be removed while the motors are running. Please provide recommendations for these filters and differential pressure switches to monitor the condition of the filters.

Please contact Jon Christensen at (801) 864-4414 as soon as possible regarding these problems. We can not reinstall the motor until we resolve the questions about vibration.

TELEPHONE MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION
INTERMOUNTAIN GENERATING STATION

TO: Jerry Avey

COMPANY: Westinghouse
Motor Field Service
(512-218-7272)

FROM: Jon Christensen

COMPANY: IPSC

DATE: April 23, 1993

TIME: 15:30

SUBJECT TITLE: Air Compressor Motor Questions

We discussed the repair procedure by TRAM and the problems we have been having with vibrations. I told him the axial vibration appears to be related to magnetic center because the vibration stops as soon as the motor is turned off. The vertical and horizontal vibration appears to be mechanical because it slowly trends down after the motor is turned off. He said Westinghouse maintains extremely tight tolerances on these motors because they are high speed.

They recommend a diametrical clearance between the bearings and journal of 5 to 8 mils, with a clearance fit of 1 to 2 mils between the bearing housing and bearing. They require a maximum taper on the shaft journal of **.3 mils**. The air gap may no longer be correct after the journal was cut. The concentricity of the rotor iron with the shaft journal is of utmost importance. This can be checked when the rotor is being balanced and is being rotated on the journal surfaces by using a dial indicator. Most repair shops check the concentricity when the shaft is on the lathe and this measurement only checks the concentricity of the journal with respect to the shaft.

He asked if the motor appeared to lock into a position when it was started. If the motor appears to latch into position and does not hit the thrust surfaces of the bearings then it has found magnetic center. However, magnetic center may be changing giving an axial vibration if the air gap is incorrect. The acceptable tolerances on air gap is no individual measurement may differ from the average of the four measurements by more than 15%.

In order to check for a correct air gap, phase measurements should be taken with the vibration readings. If the phase angle varies significantly the shaft is being pulled up and around by the uneven air gap.

I asked about the possibility of adding air filters to the inlet of the motors. He said he had reviewed the outline drawing and he felt it would be possible to add Airmaze filters without significant problems. This type of filter uses an expanded metal screen which can not block the flow of air when it becomes dirty. An adhesive is used to coat the filters and the dirt adheres to the adhesive. He said Westinghouse would prefer the filters on the inside but they could be added externally. We discussed the addition of air pressure switches to monitor the condition of the filters. He said Westinghouse would prepare a proposal showing a new air cabinet with air filters and a differential pressure switch. They would have the proposal ready in about two weeks.

The Intermountain Power Project has four Westinghouse 700 HP induction motors used as drivers for Elliot Air Compressors. We would appreciate your providing us with technical assistance on the design and operation of the sleeve type bearings for these motors. And for providing information regarding the possibility of additional filtering of the motor cooling air.

The nameplate data on these motors follows:

HP: 700	FLA: 53	MOUNTING: Horizontal
RPM:3582	LRA:384	ASSY: F-1
POLES:2	KVA CODE: G	BEARINGS: Split Sleeve
FRAME: LLD	ENCL: D.G.	DUTY: Continuous
VOLTAGE: 6600	S.F.: 1.0	Stator RTD: 100 ohm
Phase: 3	Ambient/Rise: 40/80 C	End Play: .50 inch min.

These motors were purchased by Elliot Co under Westinghouse Shop Order number S.O. 82F52938.

We recently lost an inboard bearing on one of these motors due to loss of the lubricating oil. The motor ran for approximately four hours with minimal oil . This caused the bearing to reach temperatures in excess of 260 F and resulted in the total destruction of the bearing and oil seal. In addition, there was some shaft damage.

We had a local motor repair shop skim cut the damaged portion of the shaft, build the shaft back up by welding and then re-machine the shaft. The damaged bearing was replaced and the oil seal rebuilt. When we put the motor back in service the vibration on the motor was significantly higher than before the failure.

There has been a significant increase in the axial vibration at 3X running speed and in horizontal and vertical vibration at 1X and 2X. Please provide us with your recommended bearing fits (bearing to shaft and bearing to housing) and with information about the setting of the motor shaft comparing mechanical center to magnetic center.

In addition, please provide us with any available information regarding the addition of air filters to these motors. The air compressors are continually leaking oil which is coating the windings of these motors. We would like to add external disposable or mesh type filters which can be removed while the motors are running. Please provide recommendations for these

filters and differential pressure switches to monitor the condition of the filters.
Please contact Jon Christensen at (801) 864-4414 as soon as possible regarding these problems. We can not reinstall the motor until we resolve the questions about vibration.

TELEPHONE MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION
INTERMOUNTAIN GENERATING STATION

TO: Jerry Avey

FROM: Jon Christensen

COMPANY: Westinghouse Motor Field Service

COMPANY: IPSC

DATE: April 23, 1993

TIME: 15:30

SUBJECT TITLE: Air Compressor Motor Questions

From the description of the problems it appears the axial vibrations may be caused by an uneven air gap. Because this is a 3600 rpm motr the tolerances

IP12_005010

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: S. Gale Chapman

FROM: Dennis K. Killian

DATE: July 27, 1995

SUBJECT: 'D' Service Air Compressor Motor Failure

FILE: 01.12.02, 43.5802

The 'D' Service Air Compressor Fan Motor failed, on July 25, 1995, because of a phase to ground short circuit. The failure was caused by a combination of cyclic stress due to frequent starting and insulation contamination. The overcurrent (50/51) and ground fault relay then tripped the motor circuit breaker and deenergized the motor. The motor required a complete stator rewind and then was returned to service.

A detailed analysis of the failure mechanism and recommendations to minimize cost associated with this type of failure follows:

<u>Failure Description</u>

The Unit 2 `B' FD Fan Motor failed shortly after being restarted on June 5, 1995 at 7:46:48. The PI monitoring system indicates the motor ran for approximately 12 seconds after the motor inrush current dropped to normal running current levels. The motor circuit breaker differential and ground fault protective relays both had trip indication.

The motor was then tested, both at the motor leads and circuit breaker at 5000 VDC and it passed the Megger tests without any indication of problems. The motor was then high potential tested, at the motor leads, and failed at 9000 VDC. The motor drive end cover was removed and visually inspected. There was a slight burn mark at approximately 9:00 o'clock on the motor end winding.

<u>Failure Mechanism</u>

The end winding was removed from the motor at the black spot and was dissected. A turn to turn short was evident in the winding. Four strands of the individual turn were melted together and the insulation was charred and broken in the area of melted strands.

Analysis of the winding construction indicated the turn insulation consisted of the enamel coating on the magnet wire and half lapped mica tape. This type of insulation should be adequate for the calculated 33 volts between turns. However it appeared the winding end turn caused the mica tape to separate in the turn area so that the enamel coating provided essentially all of the turn insulation in this area.

Recommendations

Additional insulation should be added between individual turns to provide a greater margin of protection. The amount of insulation should be judiciously selected to minimize the reduction in heat dissipation from the windings.

Since turn to turn failures typically progress very slowly, an increased emphasis should be placed on periodic testing of these motors to prepare for rewinds on a scheduled basis. These tests should consist of polarization index testing and surge testing. The policy of stopping and starting these motors should be reviewed. Typically the greatest stator winding insulation stresses occur during staring. This motor failure occurred immediately following starting.

INTERMOUNTAIN POWER SERVICE CORPORATION

☐ REQUISITION FOR CAPITAL EQUIPMENT

☒ PURCHASE AUTHORIZATION FOR EXPENSE ITEMS

Purpose of Materials, Supplies or Services:

Generator and Generator Auxiliaries Capability Study

Date: Sept 24, 2001	
Req./PA No: 172583	
P.O. No:	
Vendor:	
Terms:	
FOB:	
Ship Via:	
Conf. To:	

Suggested Vendor: Alstom

Account No. 002TGX-402

Work Order No. 01-19846

Project No. IGS01-02

Qty	Unit	Description: Noun / Adjective / Catalog # / Seller or Manufacturer	Unit Cost	Extension
1	Lot	Perform an engineering study to determine the	$80,000.00	$80,000.00
		feasibility of increasing the rating of General		
		Electric Generators 280T150 and 280T151. Study		
		to be performed in accordance with the attached		
		scope.		
		TOTAL ESTIMATED COST		$80,000.00

Remarks: Study required to determine operating parameters of the generator after the Turbine upgrade.

Delivery requested by [Date] 10-01-01 Originator Jon P. Christensen

Dept. Mgr/Supt. Date Station Manager Date Operating Agent Date

January 7, 2011

Bajarang Agrawal
Arizona Public Service

Dear Mr. Agrawal:

Intermountain Power Project Generator Tests

We request your assistance in performing power system stabilizer (PSS) and WSCC mandated modeling tests on the generators at the Intermountain Power Project. This testing includes performing PSS verification tests on February 19, 1999 while both generators are fully loaded. In addition, we will complete WSCC required tests when the Unit 1 Generator is removed from service, for a scheduled maintenance outage, during the night of Feb 19.

Please provide a written test procedure, test equipment and technical direction to assist us in completing these tests. You should coordinate your schedule and work scope through Jon P. Christensen. The Intermountain Power Service Corporation will be responsible for conducting these test and waives any liability claims against Arizona Public Service Corporation arising out of the performance of these tests. A purchase order is attached to cover your costs in assisting us in conducting these tests.

If you have any questions or require additional information, please contact Jon P. Christensen at (435)-864-6481 or through the Internet at jon-c@ipsc.com

Sincerely,

S. Gale Chapman
President and Chief Operating Officer

JPC:DB

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: Joe Hamblin

FROM: Jerry Hintze

DATE: February 27, 1994

SUBJECT: AQCS Building HVAC Modifications

FILE: 01.12.09, 43.0802

We have reviewed work order 94-51024 which requests immediate modification of the return air fans in the AQCS Buildings from variable blade pitch to variable frequency drives. This modification was requested because of the increasing difficulty in procuring repair and/or replacement parts for the existing variable pitch fans. Our review indicates repair parts are still available, for a limited time, from the fan manufacturer and sufficient parts have been shipped from the manufacturer to repair the existing equipment.

We intend to review the operation of this equipment for the 1995-1996 Budget Year and we will submit a capital project, if modifications are required, at that time.

If you have any questions or require additional information, please contact Jon P. Christensen at Extension 6481.

JPC:JHN:

7200 Volt Distribution System Design Philosophy

By design, one auxiliary transformer supplies two lineups of 6900 volt switch gear. Unit Auxiliary Transformer 1A supplies Switchgear 1A1 and 1A2 and Unit Auxiliary Transformer 1B supplies Switchgear 1B1 and 1B2. Each line up of switchgear was designated as a small motor bus or a large motor bus. The 1A1 and 1B1 switchgear are small motor buses while the 1A2 and 1B2 buses are large motors buses. The small motor buses supply power to almost all of the secondary unit substations (SUS's) and to motors less than 1000 HP. The large motor buses supply power to all of the motors over 1000 HP, some small motors, and to the cooling tower SUS's.

Because the large motor buses supply loads with a higher total current requirement they operate at lower voltages than the small motor buses. The original design engineering firm, Black and Veatch, compensated for the expected lower operating voltages, on the large motor bus, by requiring all of the large motors to be designed to operate with rated voltages of 80% to 110% . However, some of the motors purchased as part of the equipment packages were provided with operating ranges of 90% to 100% of rated voltage. The air compressor motors and pulverizer motors fall into this category. Although the motors are provide with different voltage operating ranges performance characteristics (losses, power factor and efficiency) are all based on the rated voltage.

Rated motor voltage is based on system supply voltage. For a 6900 volt system motors are specified with a rated voltage of 6600 volts. This voltage differential compensates for line losses between the motor terminal and the source. The drop in voltage is especially significant during motor starting when the motor inrush current is normally 6 to 8 times rated current. Generating station high voltage motors were all specified with a nominal rating of 6600 volts.

The auxiliary transformers have 26 kV delta connected primaries with dual 7.2 kV wye connected secondaries. They were provided with a single set of tap changers on the primary side. Two 2 1/2% taps were provide above and two 2 1/2% taps below rated voltage. Because the taps were provided on the primary connection of the transformer, changing the taps affects both secondary windings and changes the voltage on both a large and small motor bus.

Operating Experience

During start-up the auxiliary transformers were set on tap position number three to provide the best operating range for the 6900 volt bus from minimum unit load to full unit load of 840 MWg. This tap setting provided a average bus voltage of 7000 volts on the small motor bus and 6750 volts on the small motor bus.

Subsequently two problems were identified with the existing operating voltages on the 6900 volt bus . First, the pulverizer motors, which are installed on the small motor bus, developed a heating problem. Generally, the motors for the generating station were specified to have Class F insulation with a Class B temperature rise. Class F insulation allows operation at up to 160 C (40 C ambient with a 120 C temperature rise) with no loss of life. By limiting the motor operating temperatures to a Class B temperature of 120 C (40 C ambient with a 80 C temperature rise) motor insulation life is extended. Specifying a Class F insulation with a Class B rise builds in a safety margin to compensate for the variability of operating conditions and for differences between calculated load requirements and actual load requirements.

The pulverizer motors were specified to have an 80 C rise (120 C total temperature) and yet over time they began to operate between 140 to 150 C. Testing by the motor manufacturer indicated the problem was partially caused by the motor operating voltage. Operating a motor above nameplate voltage causes higher magnetizing currents within the motor and increases motor heater . Our testing indicates operating the pulverizer motors at 7000 volts increases motor temperatures by 6 to 8 C.

Degradation of the internal cooling system and RTD measurement errors caused the rest of the temperature rise. The cooling system problems were corrected and the motors continued to operate with in the 130 C to 140 C range under high ambient temperature and maximum load conditions.

The second problem associated with bus voltages was caused by duplicate motors being operated on different type buses. The A, B and C air compressor motors are installed on small motor buses while the D air compressor is installed on a large motor bus. All of the timed over current relays, for the air compressor motors, were originally set based on rated voltage. Because the 'D' air compressor motor was installed on a large motor bus, with a lower operating voltage, it frequently tripped during starting. Our testing showed the motor current was just starting to return to normal levels when the motor over current relays tripped the supply circuit breaker.

Motor starting current is typically 6 to 8 times full load current. When a motor is started, this higher current level lasts until the motor is accelerated from standstill to near rated speed. The time required to accelerate a motor from standstill to rated speed is called acceleration time and is a function of the accelerating torque. Accelerating torque is a function of the difference between motor torque and the torque of the load. Since motor torque is a function of motor current and current is proportional to voltage, lower operating voltages increase the time required to accelerate a to rated speed. The longer it takes a motor to reach rated speed the longer the motor current stays at higher levels. Higher current levels cause increased winding temperatures and raise the possibility of damaging the windings.

Protective relays are set to trip the power circuit to motors if the starting current does not decrease to normal levels within the time frame specified by motor manufacturers. Since the 'D' compressor motor required more time for the starting current to decay to normal values it would frequently trip during starting. The motor protective relay settings were changed to compensate for the longer starting times. These changes were within the motor manufacturers recommendations. After the changes were made the D air compressor motor no longer tripped during starting.

Current Operating Status

When the generator output was increased from 840 MWg to 875 MWg the load increased on the auxiliary buses resulting in a slight lowering of the auxiliary bus voltages. Typically the large motor bus now operates at 6600 volts and the small motor bus operates at 6900 volts. Typical bus conditions are shown in Table 1.

Unit 6900 Volt Switchgear Operating Conditions (Unit load at 875 MWg)		
Switchgear	Voltage	Current
1A1	6950	1000
1A2	6600	1800
1B1	6900	900
1B2	6600	1725
2A1	6850	800
2A2	6600	2000
2B1	6900	800
2B2	6600	1650

These values vary depending on which equipment is in service, but generally the large motor buses are running 150 volts less and the small motor buses are running 50 to 100 volts less when the auxiliary bus load is increased to provide 875 MWg output from each generator.

The reduced operating voltage on the large motor bus required additional changes to the protective relays for the 'D' air compressor motor. This setting was changed to the recommended maximum recommended by the motor manufacturer. However, the lower bus voltages helped reduce the operating temperature of the pulverizer motors due to increased magnetizing current but, other operating changes (poor quality coal, increased quantities of rocks, etc) have offset the temperature reduction and the motors now operate in the 150 to 160 C range during worst case conditions.

Alternative Evaluation

There are several alternatives which could reduce problems associated with the low operating voltages on the large motor bus. First the taps could be changed on the auxiliary transformers to raise the voltage. Using the next tap setting would raise the bus voltage 2 ½ %. This would raise the large motor bus voltage to 6765 volts but it would also raise the small motor bus voltage to ≈7050 volts. loading could be more balanced to provide more even voltage between the large and small motor buses.

6900 Volt Distribution System Loading Analysis

Summary

The existing voltage imbalance between the large motor buses and the small motor buses is a function of the design of the 6900 volt distribution system. Although this imbalance has caused problems with starting the 'D' air compressor motor, changing the existing design of the large and small motor buses is not economically justified. Starting problems with the motor has been corrected with relay setting revisions. The current operating conditions are within the motor manufacturer's recommendations and do not adversely affect the life of the motor.

6900 Volt Distribution System Design Philosophy

By design, one auxiliary transformer supplies two lineups of 6900 volt switch gear. Unit Auxiliary Transformer 1A supplies Switchgear 1A1 and 1A2 and Unit Auxiliary Transformer 1B supplies Switchgear 1B1 and 1B2 (Figure 1). Each line up of switchgear was designated as a small motor bus or a large motor bus. The 1A1 and 1B1 switchgear are small motor buses while the 1A2 and 1B2 buses are large motors buses. The small motor buses supply power to almost all of the secondary unit substations (SUS's) and to motors less than 1000 HP. The large motor buses supply power to all of the motors over 1000 HP, some small motors, and to the cooling tower SUS's.

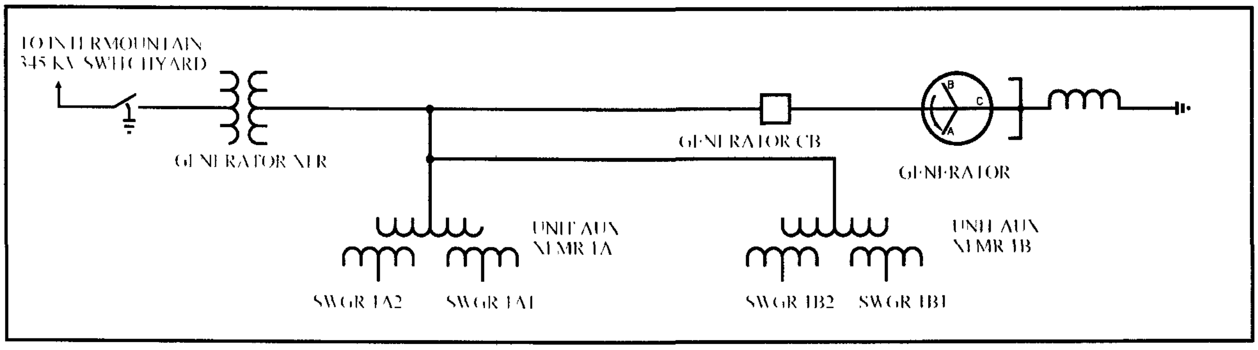

Figure 1 - 6900 Volt Distribution System

Because the large motor buses supply loads with a higher total current requirement they operate at lower voltages than the small motor buses. The original design engineering firm, Black and Veatch, compensated for the expected lower operating voltages, on the large motor bus, by requiring all of the large motors to be designed to operate with rated voltages of 80% to 110%. However, some of the motors, (i.e. air compressor motors) purchased as part of equipment packages were provided with a range of 85% to 110%. Although the motors are provided with different voltage operating ranges performance characteristics (losses, power factor and efficiency) are all based on the rated voltage.

Rated motor voltage is based on system supply voltage. For a 6900 volt system motors are specified with a rated voltage of 6600 volts. This voltage differential compensates for line losses between the motor terminal and the source. The drop in voltage is especially significant during motor starting when the motor inrush current is normally 6 to 8 times rated current. All of the generating station high voltage motors were specified with a nominal rating of 6600 volts.

The auxiliary transformers have 26 kV delta connected primaries with dual 7.2 kV wye connected secondaries. They were provided with a single set of tap changers on the primary side. Two 2 1/2% taps were provide above and two 2 1/2% taps below rated voltage. Because the taps were provided on the primary connection of the transformer, changing the taps affects both secondary windings and changes the voltage on both a large and small motor bus.

Operating Experience

During start-up the auxiliary transformers were set on tap position number three to provide the best operating range for the 6900 volt bus from minimum unit load to full unit load of 840 MWg. This tap setting provided an average bus voltage of 7000 volts on the small motor bus and 6700 volts on the small motor bus.

Subsequently two problems were identified with the existing operating voltages on the 6900 volt bus . First, the pulverizer motors, which are installed on the small motor bus, developed a heating problem. Generally, motors for the generating station were specified to have Class F insulation with a Class B temperature rise. Class F insulation allows operation at up to 160 C (40 C ambient with a 120 C temperature rise) with no loss of life. By limiting the motor operating temperatures to a Class B temperature of 120 C (40 C ambient with a 80 C temperature rise) while requiring the motors to be designed for Class F insulation motor life is extended. Specifying a Class F insulation with a Class B rise builds in a safety margin to compensate for the variability of operating conditions and for differences between calculated load requirements and actual load requirements.

The pulverizer motors were specified to have an 80 C rise (120 C total temperature) and yet over time they began to operate between 140 to 150 C. Testing by the motor manufacturer indicated the problem was partially caused by the motor operating voltage. Operating a motor above nameplate voltage causes higher magnetizing currents within the motor and increases motor heating . Our testing indicates operating the pulverizer motors at 7000 volts increases motor temperatures by 6 to 8 C.

Degradation of the internal cooling system and RTD measurement errors caused the rest of the temperature rise. The cooling system problems were corrected and the motors continued to operate with in the 130 C to 140 C range under high ambient temperature and maximum load conditions.

The second problem associated with bus voltages was caused by duplicate motors being operated on different type buses. The A, B and C air compressor motors are installed on small motor buses while the 'D' air compressor is installed on a large motor bus. All of the timed over current relays, for the air compressor motors, were originally set based on rated voltage. Because the 'D' air compressor motor was installed on a large motor bus, with a lower operating voltage, it frequently tripped during starting. Our testing showed the motor current was just starting to decay to normal levels when the motor over current relays tripped the supply circuit breaker.

Motor starting current is typically 6 to 8 times full load current. When a motor is started, this higher current level lasts until the motor is accelerated from standstill to near rated speed. The time required to accelerate a motor from standstill to rated speed is called acceleration time and is a function of the accelerating torque. Accelerating torque is the difference between motor torque and load torque. Since motor torque is a function of motor current and current is proportional to voltage, lower operating voltages increase the time required to accelerate a motor to rated speed. Factory design calculations for the air compressor motors indicate 4.464 seconds are required to accelerate the motor to rated speed when the motor is started at full voltage and 7.341 seconds are required at 85% voltage.

The longer it takes a motor to reach rated speed the longer the motor current stays at higher levels. Higher current levels cause increased winding temperatures and raise the possibility of damaging the windings. In order to reduce the probability of damaging the motors during starting, Westinghouse specified a maximum starting of 7 seconds when the motor is started with the windings hot or cold at rated voltage. For reduced voltage starting a maximum of 18 seconds with a cold winding and 10 seconds with a hot winding is allowed.

Protective relays are set to trip the power circuit to motors if the starting current does not decrease to normal levels within the time frame specified by motor manufacturers. Since the 'D' compressor motor required more time for the starting current to decay to normal values it would frequently trip during starting. The motor protective relay settings were changed from 5 seconds to 5.5 seconds to compensate for the longer starting times. After the changes were made the 'D' air compressor motor no longer tripped during starting.

Current Operating Status

When the generators were re-rated to 875 MWg the load increased on the auxiliary buses resulting in a slight lowering of the bus voltages. Typically the large motor bus now operates at 6600 volts and the small motor bus operates at 6900 volts at full unit load. Typical bus conditions are shown in Table 1.

Unit 6900 Volt Switchgear Operating Conditions (Unit load at 875 MWg)		
Switchgear	Voltage	Current
1A1	6950	1000
1A2	6600	1800
1B1	6900	900
1B2	6600	1725
2A1	6850	800
2A2	6600	2000
2B1	6900	800
2B2	6600	1650

Table 1 - Typical Bus Loading

These values vary depending on which equipment is in service, but generally the large motor buses are running 100 volts less and the small motor buses are running 50 to 100 volts less than before the re-rate.

The lower bus voltages caused the 'D' air compressor motor to begin tripping again during starting. The protective relays time delays were changed to 6 seconds to compensate for the increase starting duration. Since the air compressor motors are started at various bus voltages this is close to the maximum setting to provide full voltage starting motor protection.

The pulverizer motors are once again running at near their maximum stator winding temperatures during hot weather. However this increase is caused by increased motor load due to poor quality coal. The small motor bus voltage is presently close to ideal for the pulverizer motors.

<u>Alternatives to Correct Auxiliary Bus Voltages</u>

Using existing equipment, there are only two alternatives for adjusting the bus voltages. The first alternative is changing the tap settings on the auxiliary transformers. Since the transformers taps are in 2.5% increments, under existing conditions, changing the taps would raise the bus voltages to ≈7150 volts on the small motor bus and ≈6750 volts on the large motor bus. The higher voltage on the large motor bus for the 'D' air compressor motor would reduce starting times and the possibility of trips. But the higher voltage on the small motor bus would increase the operating temperature of the pulverizer motors and reduce their life. This alternative is not viable because of the load imbalance between the two buses.

The second alternative is to balance the bus voltages by re-arranging loads on the buses. There is almost a two to one margin between the total load on the large motor bus compared to the small motor bus. It is not practical or economically feasible to totally balance the bus loading. Large motors can not be moved to the small motor bus without adversely affecting bus voltages during motor starting. One major load, the cooling tower secondary unit substations (CT SUS's) could be moved to the small motor bus but this would only result in a shift of ≈150 amperes and result in a shift of ≈50 volts on each bus. The estimated cost to move the CT SUS's by installing new power cable and splicing the existing circuits (in existing manholes) is $75,000. This project is not justified.

One other alternative would be to move the 'D' air compressor to a small motor bus. There is existing 6900 volt cable, installed in the cable trays, which could be used for this job. New control cable would have to be installed and the existing power cables rerouted. The last spare bifurcated circuit breaker on the 2B1 6900 volt switchgear would be utilized for this change. We estimate the following costs for this project:

Engineering	$ 1,000
Material	$ 3,000
Labor	$ 9,500
Total	$13,500

The 'D' Air Compressor Motor is presently operating within design limits established by the manufacturer. Unless additional load is added to the 2B2 bus, moving the air compressor to a small motor bus is not justified. If the load on the switchgear increases, resulting in lower bus voltage, revising the protective relay scheme to include both levels of current and the rate of change of the starting current should be considered for this motor. Relay changes or relocating the motor to the small motor bus should then be evaluated.

Auxiliary Electric Control Panel
Indicating Lamp Resistor Heating Problem

The resistors, used as voltage dropping resistors, for the indicating lamps in the Auxiliary Electric Control Panels are TEPRO Type TSM. 5. They are rated 2490 ohms, 1% tolerance with a dual power rating of 5.0 watts with a 275 C maximum hot spot temperature and 6.5 watts with a 350 C maximum hot spot temperature. The indicating lamps are T1-3/4 flange base, 28 volt, 0.04 amperes, type 327 lamps designed for 7500 hours life at 24 volts. The nominal design life at 28 volts is 4000 hours.

It is possible to change these resistors out with new resistors having a higher power rating. They can be replaced with TEPRO Type TSM 7 which have a dual power rating of 7.0 watts with a 275 C maximum hot spot temperature and 9.0 watts with a 350 C maximum hot spot temperature. New mounting boards would have to be fabricated because the TSM 7 resistors are longer than the original resistors (1.218 inches instead of 0.875 inches). These mounting boards would have to be capable of withstanding the maximum hot spot temperature of 350 C. Be very careful if you decide to substitute another brand of resistor. The TEPRO resistors have some unique characteristics suited to this application.

While replacing the resistors with new resistors having a higher power rating will solve the problem of heat damaging the resistor it will not reduce the heat output. The original design of this circuit was based on a nominal voltage of 125 volts. Because the actual voltage is 135 volts and up to 140 volts, when the station batteries are being equalized charged, the resistors are being operated at near their thermal limits.

Apparently the original circuit was designed in accordance with the following:

$$R_{lamp} = \frac{28 \text{ volts}}{0.040 \text{ amperes}}$$

$$= 700 \text{ ohms}$$

$$R_{resistor} = 2490 \text{ ohms}$$

$$R_{circuit} = R_{lamp} + R_{resistor}$$

$$= 3190 \text{ ohms}$$

$$I_{circuit} = \frac{V_{circuit}}{R_{circuit}}$$

$$= \frac{125 \text{ volts}}{3190 \text{ ohms}}$$

$$= 0.0392 \text{amperes}$$

IP12_005026

$$V_{resistor} = I_{circuit} \times R_{resistor}$$
$$= (0.0392 \text{ amperes})\,(2490 \text{ ohms})$$
$$= 97.6 \text{ volts}$$
$$V_{lamp} = (0.0392 \text{ amperes})\,(700 \text{ ohms})$$
$$= 27.4 \text{ volts}$$

$$P_{resistor} = V_{resistor} \times I_{circuit}$$
$$= 3.83 \text{ watts}$$

This is well within the power rating of the resistor.

But since the circuit is being operated at 135 volts, the circuit parameters change as follows:

$$I_{circuit} = \frac{135 \text{ volts}}{3190 \text{ ohms}}$$
$$= 0.042 \text{ amperes}$$
$$V_{resistor} = 105.4 \text{ volts}$$
$$V_{lamp} = 29.6 \text{ volts}$$
$$P_{resistor} = 4.46 \text{ watts}$$

Although this is still with in the rating of the resistor it does approach the limit where the resistor may have hot spots of up to 275 C. In addition, the lamp life will be reduced because it is operating at higher than design voltage. This situation is aggravated when the batteries are being equalized and the operating voltage is 140 volts. Under these conditions

$$I_{circuit} = \frac{140 \text{ volts}}{3190 \text{ ohms}}$$
$$= 0.044 \text{ amperes}$$
$$V_{resistor} = 109.3 \text{ volts}$$
$$V_{lamp} = 30.7 \text{ volts}$$
$$P_{resistor} = 4.80 \text{ watts}$$

I recommend replacing the resistors, which show evidence of thermal degradation, with new resistors rated at 2750 ohms. This will reduce heating at the resistors and will extend the lamp life. The new resistors should be TEPRO Type TSM. 5.

If you have any questions or need additional, please let me know.

INTERMOUNTAIN POWER SERVICE CORPORATION

TELEPHONE MEMORANDUM

TO: Jon Christensen

COMPANY: IPSC

FROM: John Morrow/Jerry Vaughn

COMPANY: Black & Veatch

DATE: 11/13/01

TIME:

SUBJECT TITLE:

Generating Station Main Battery

DISCUSSION DOCUMENTATION:

(Jon) IPSC is in the process of replacing the main station batteries and essential service batteries for both generating stations. The replacements are scheduled for the next maintenance outages. IPSC has ordered replacement flooded cell batteries similar to the batteries which were installed originally. The replacement main station batteries are 2400 Ah. The battery manufacturer is having difficulty meeting the required ship date for the flooded cell batteries and has offered a 3000 Ah valve regulated battery as an alternative. GNB is willing to ship the valve regulated batteries within two weeks, provide a full 5 year warranty with a 15 year prorated warranted (compared to the full one year and 19 year prorated for the flooded cells) and provide the batteries at the same price they quoted for the flooded cells. The normal cost for the 2400 Ah flooded cell is $90,000 while the 3000 Ah valve regulated battery is $143,000. Would Black & Veatch consider using a valve regulated battery as a main station battery for a generating facility?
(Jerry) I did the original design for the batteries at the Intermountain Generating Station, so I am familiar with this installation. It has taken several years for me to feel comfortable with using valve regulated batteries as station batteries but we do use them now for gas turbine applications and for over seas installations. We have used these batteries for steam turbine applications. In EPC contracts we use valve regulated batteries almost exclusively. There are significant savings because these batteries do not require special rooms with acid resistant floors, monitored ventilation, containment, emergency eyewash stations etc. But you already have all of those things.
You can change the batteries online. The chargers at IPP are designed with battery eliminator circuits and the batteries can be completely isolated.
(Jon) I worry about the loss of AC power and the resultant damage to the turbine generator if we change the batteries online.
(Jerry) You could configure the batteries so you have two battery chargers supplying the

load while you work on a single battery. Then the only risk you have is a black trip.
(Jon) Although the risk is small the consequences are significant. I am not comfortable with having the turbine generator unprotected during the time required to change the batteries out.
(Jerry) With planning you could minimize the time without the battery.
(Jon) I am also concerned with the risks during connecting and disconnecting the battery because of the arc potential and the fault capability of the batteries.
(Jerry) Of course, the safest way to change the batteries is with the unit offline.
(Jon) How do you feel about valve regulated batteries, specifically with GNB Absolyte batteries?
(Jerry) It has taken me several years to feel comfortable with these batteries. I am aware of several people who hate Absolyte batteries and also of those who will only use Absolyte batteries. Absolyte valve regulated batteries were the first on the market. They did have some initial problems because they developed the technology. They started with the Absolyte, then the Absolyte II and then the Absolyte IIP. Initially, they had problems with both design and manufacturing. They tried glass banding to compress the plates during manufacturing but that caused problems. Then they removed the bands but did not get good plate compression which created gaps between the plates. There was also a problem with thermal run away which ultimately leads to failure of the battery. All of these problems seemed to be resolved now.
(Jon) We have used Absolyte II's and recently we received replacement IIP's for all of our UPS's. But we have had very disappointing results with these batteries. They are only lasting 5 to 8 years before replacement is required. We do recognize that part of the problem is the battery room temperature. Some of these batteries are installed in rooms like the ID Fan Drive rooms where the temperature ranges between 80 and 100 F.
(Jerry) Just like in the early days of power plant electronics, you have a learning curve with any new equipment application. When we first tried to use electronics, in a power plant environment, we had problems because the electronics were not "hardened". They could not handle the temperature or dirt and contamination. The original batteries were not hardened for a power plant environment. They were, and they still are, sensitive to temperature. You understand temperature run-away. Temperature run-away occurs when the battery is heavily loaded causing it to heat up. If the battery has been installed so that it can not dissipate the heat, it gets hotter until it fails. The installation of these batteries is critical, you must leave air space around the battery. But you do not have this problem in the main battery rooms at IPP. Your rooms are cooled and have enough space so the batteries can be installed with adequate cooling space. Just make sure you leave space all around the battery.
(Jon) They are offering the next generation of battery the Absolyte XL. Are you familiar with the XL?
(Jerry) No I am not. How is the warranty set up? What criteria do you use for pass or fail? If the battery fails will they replace it with a flooded cell battery?
(Jon) We are still checking on the warranty, but I believe we would ask for a 90% capacity test and we have asked that we have the option of replacing a failed battery with a flooded cell battery.
(Jerry) I am not a great fan of capacity testing for flooded cell batteries, because the test only tells what the capacity was before the test, not what it is after the test. But a capacity test on the valve regulated batteries would be a good idea. I would test enough, during your warranty period, so you were confident the batteries were working correctly before the five year warranty was over. I would probably test after two years and then annually.

You do not want the batteries to fail in 5 years 6 months.
(Jon) Our experience has been these batteries fail very fast.
(Jerry) They do not fail fast. They will give you a warning of decreasing capacity if you test them regularly. They are different and do not give you any visual indication. On a flooded cell you can look into the jar and see the plates to determine if they are warping or damaged, you can see if any sediment is forming, you can see internal damage or leaks around the posts. On a valve regulated battery you can only rely on voltage measurements and load tests. They require maintenance , probably more maintenance then a flooded cell and they are less forgiving about incorrect installation or maintenance. (Jon) Would you consider replacing the flooded cells at IPP with valve regulated batteries?
(Jerry) You understand GNB is using this installation as a marketing tool. They are giving you an incredible deal. IPP's battery rooms will handle the installation of the valve regulated batteries without any problem. They are offering a warranty which allows changing back to flooded cell batteries if the batteries fail. I would use the valve regulated batteries. I would test them regularly. The valve regulated batteries should work well in this application if they are installed and maintained correctly. I think valve regulated batteries can work well. Although people have had good and bad experience with these batteries I have to attribute the difference to installation, operating and maintenance practices. The people who have bad experiences and the people who have good experiences are both using the same battery. I do not think the problem is design or manufacturing.
(Jon) Is there any thing you would change in the installation if you used valve regulated batteries?
(Jerry) I would make sure there was air space around the batteries and I would install a battery monitoring system.
(Jon) Could you recommend a manufacturer for the battery monitor?
(Jerry) Alber makes a good monitor.

INTERMOUNTAIN POWER SERVICE CORPORATION

TELEPHONE MEMORANDUM

TO: Al Taylor

FROM: Jon Christensen

COMPANY: LADWP

COMPANY: IPSC

DATE: 11/14/01

TIME: 2:00 Pm

SUBJECT TITLE:

Station Batteries

DISCUSSION DOCUMENTATION:

(Jon) It has been a long time since we talked. I understand you are still the Relay Design Group Supervisor but you now also work with batteries.
(Al) The Substation Design Group used to handle battery design, but when Ron Schmedieke left they did not have much interest in batteries. Since the batteries are critical to the operation of the protective relays we take care of the battery designs now.
(Jon) IPSC is in the process of replacing the main station batteries and essential service batteries for both generating stations. The replacements are scheduled for the next maintenance outages. IPSC has ordered replacement flooded cell batteries similar to the batteries which were installed originally. The replacement main station batteries are 2400 Ah. The battery manufacturer is having difficulty meeting the required ship date for the flooded cell batteries and has offered a 3000 Ah valve regulated battery as an alternative. The replacement batteries are Absolyte .
(Al) Do not use Absolyte batteries. We have had nothing but problems with them
(Jon) Why do you say that? What problems have you had?
(Al) The Absolyte batteries do not last. Although they are supposed to be sealed, in normal service the pressure relief valve open. When the valve opens a little fluid leaks out. After two or three operations, the valves do not reseal and the batteries dry out. When the electrolyte dries out the cell is dead. There is also a problem with recycling the Absolyte batteries. They use some heavy metals, in addition to the lead, in the construction of the batteries. Most recycling facilities can not recycle Absolyte batteries.
(Jon) What model of Absolyte are you using? We had a similar problem with the initial battery installation for some of our UPS's. But those were Absolyte II's. Supposedly that problem was solved by later models of Absolyte batteries. Back when we installed the UPS's in the early 1990's, I discussed batteries with Ron and he recommended the Absolyte.

(Al) I am not sure what model we are using. In the late 1980's to the early 90's Ron had most of our batteries changed from flooded cell to Absolyte (valve regulated). We are in the process of replacing these batteries because they are drying out and failing. We can barely keep up with the replacements. We have been having problems for some time. I have looked back at some of Ron's paperwork and I am not sure why he was such a great fan of the Absolyte. They were more expensive and require more maintenance. On a flooded cell you can add water and they typically last 15 to 20 years.
(Jon) What are you replacing them with?
(Al) We have been replacing them with C&D valve regulated batteries. They look more like a car battery so the connections are on the top. We are also looking at using nickel cadmium (nicad) batteries. If nicad batteries are installed in the same room as the relays they do not corrode the relays like the valve regulated batteries. Since the nicad batteries are alkaline based they will not damage relays. The nicad batteries are very expensive but they have a smaller foot print for the same capacity.
(Jon) The best batteries for this type of application are lead calcium flooded Plante', but they are also very expensive. If you are installing the batteries in the same room with equipment you will have to use valve regulated batteries.
(Al) If we have a separate battery room we are thinking of going back to flooded cell batteries, but otherwise we are trying nicad and other brands of valve regulated. We are just starting our evaluation but, we are still learning, so I can not give you much information.

INTERMOUNTAIN POWER SERVICE CORPORATION

TELEPHONE MEMORANDUM

TO: Jeff Thornburg

FROM: Jon Christensen

COMPANY: LADWP

COMPANY: IPSC

DATE: 11/13/01

TIME:

SUBJECT TITLE:

Station Batteries

DISCUSSION DOCUMENTATION:

(Jon) What has been your experience with valve regulated batteries?

(Jeff) We have not had good experience. They do not last very long. Typically they only last about 8 years.

(Jon) IPSC is in the process of replacing the main station batteries and essential service batteries for both generating stations. The replacements are scheduled for the next maintenance outages. IPSC has ordered replacement flooded cell batteries similar to the batteries which were installed originally. The replacement main station batteries are 2400 Ah. The battery manufacturer is having difficulty meeting the required ship date for the flooded cell batteries and has offered a 3000 Ah valve regulated battery as an alternative. GNB is willing to ship the valve regulated batteries within two weeks, provide a full 5 year warranty with a 15 year prorated warranted (compared to the full one year and 19 year prorated for the flooded cells) and provide the batteries at the same price they quoted for the flooded cells. The normal cost for the 2400 Ah flooded cell is $90,000 while the 3000 Ah valve regulated battery is $143,000. Would LADWP consider using a valve regulated battery as a main station battery for a generating facility?

(Jeff) No we would not use valve regulated batteries. We are in the process of changing back to flooded cell batteries as we work on individual projects

(Jon) Do you have any memos or reports that have analyzed the differences between the two types of batteries. Have you done an analysis?

(Jeff) No, it is more a philosophy instead of a policy. As we get involved with projects involving batteries we use flooded cell batteries instead of valve regulated. We are doing a switch yard upgrade now. We do not have the manpower or time to look at each existing battery installation. Al Taylor is very knowledgeable about batteries. You should call and talk to him.

(Jon) Thanks

FOMIS

What experience do utilities have with maintenance on large stationary battery systems consisting of lead calcium cells.

1) How often are connections tested for resistance or re-torqued.
2) What type and brand of connection compounds are being used (greases which require heating, tube type greases, or spray on material)
3) What experience do utilities have with battery post seal or cover to cell case seal failures and repair?
4) At what frequency are batteries cleaned and is cleaning based on visual inspection or measured leakage rates across cells to ground?
5) Are copies of your standard battery maintenance procedures available?

TECHNICAL EVALUATION SPECIFICATION 45180

SPARE PULVERIZER MOTOR

Summary

Based upon our evaluation of the bids submitted in response to Specification 45180 we recommend purchasing a Taiwan Electric Company (TECO) motor to be used as a spare pulverizer motor. Because we were not able to verify substantial existing operating experience for TECO motors, in similar applications, our recommendation is based on the following stipulations:

* TECO shall be required to provide a three year warranty in lieu of the specified one year warranty.

* TECO shall perform complete testing of the motor as defined by IEEE Standard 112, as last revised, and as included in the specifications as an option.

* A qualified inspector representing the Intermountain Power Service Corporation (IPSC) shall witness testing at the manufacturing facility.

* Technical Services will meet with Bob Green Electric Company to review entire bid and confirm our interpretation of the bid before final purchase order is issued.

* One set of spare bearings shall be purchased with the motor.

We estimate a total cost to purchase the TECO motor, with these stipulations, to be $80,349. This estimate is within the budgeted amount for CEP94-34 of $140,000. A comparison of the estimated costs for the two lowest cost, technically acceptable, bidders is shown in Table 1.

	TECO	Westinghouse
Motor	$63,000	$93,117
Routine Test (Witnessed)	Not Required	$4,000 (EST)
Complete Tests (witnessed)	$5,885	Not Required
Freight	Included	$2,000 (EST)
QA/QC Expense	$2,500(EST)	$2,000 (EST)
Spare Bearings	$8,964	$7,000 (EST)
Total	$80,349	$108,117

Table 1 - Two Lowest Bidders Purchase Cost Comparison

As shown on Table 1 we recommend witnessed complete testing of the TECO motor, while we would require witnessed routine testing of a Westinghouse motor because of good operating experience with existing Westinghouse motors.

Introduction

Twelve bids, representing nine motor manufacturers, were received in response to Specification 45180. The initial review of the bids was based on listing each bid based on total motor cost from lowest to highest cost. The total motor cost, used in the evaluation was based on the cost of the motor, freight to the plant site, testing costs and estimated quality control/quality assurance (QA/QC) costs. A summary of the bids received in response to Specification 45180 is contained in Table 2.

PULVERIZER MOTOR EVALUATION SPECIFICATION 45180						
BIDDER	*ROSS HILL*	*Bob Green*	*IRS*	*Bob Green*	*ARGO*	*IRS*
MANUFACTURER	Ansaldo	TECO	TECO	Siemens	GE	GE
Point of Manufacture	Italy	Tawain	Tawain	Ohio	Brazil	Brazil
Motor	$61,900	$63,000	$66,146	$68,515	$72,370	$80,007
Complete Test (Not Witnessed)	$3,200	$4,066	$5,778	$3,500	$3,400	$3,472
Complete Test (Witnessed)	$3,200	$5,885	$6,112	$3,500	$4,850	$4,966
Report (Duplicate Motor)	N/A	$1,926	$2,000	N/A	$1,300	$1,344
Freight	included	included	included	$2,500	$3,500	included
QA/QC Inspection	$2,000	$2,500	$2,500	$2,250	$3,500	$3,500
TOTAL COST (Complete Test)	$67,100	$69,566	$74,424	$76,765	$82,770	$86,979
TOTAL COST (Witness Complete)	$67,100	$71,385	$74,758	$76,765	$84,220	$88,473
BIDDER	*Bob Green*	*Visalia*	*Westinghouse*	*ABB*	*IRS*	*Reliance*
MANUFACTURER	Toshiba	TECO	Westinghouse	ABB	Magnetek	Reliance
Point of Manufacture	Brazil	Tawain	Texas	Brazil	Wisconsin	North Carolina
Motor	$86,000	$87,781	$93,117	$102,350	$128,333	$135,206
Complete Test (Not Witnessed)	included	$3,800	$7,310	included	$8,667	$6,250
Complete Test (Witnessed)	$1,925	$5,500	$12,676	$5,300	$13,000	$11,250
Report (Duplicate Motor)	N/A	$1,800	N/A	N/A	N/A	N/A
Freight	included	included	$2,000	included	included	included
QA/QC	$3,500	$2,500	$2,000	$3,500	$2,000	$2,250
TOTAL COST (Complete Test)	$89,500	$94,081	$104,427	$105,850	$139,000	$143,706
TOTAL COST (Witness Complete)	$91,425	$95,781	$109,793	$111,150	$143,333	$148,706

Table 2 - Motor Cost Comparison

IP12_005037

TECHNICAL EVALUATION

Overview

The initial list of twelve bids was reduced to the nine motor manufacturers by selecting the lowest bid from each manufacturer. The specific operating characteristics of each motor and a comparison of the specification requirements is shown in Table 3.

PULVERIZER MOTOR (SPECIFICATION 45180) TECHNICAL EVALUATION

MANUFACTURER	SPECIFIED	GE	TECO	ABB	Magnetek
Model		8509S	AECK	QLGH500H8	7407
Rated Speed	887	885	888	892	882
Horsepower	800	800	800	800	800
Service Factor	1.15	1.15	1.15	1.15	1.15
Full Load Current		68	67	66	66
Locked Rotor Current (%)	650 maximum	650	642	650	568
Enclosure Type	TEFC	TEAAC	TEAAC	TEAAC	TEAAC
Frame		8509S	5012	500	7407
Insulation Class	F	F	F	F	F
Rotor Construction	Double Cage	Double Cage	Single Cage	Double Cage	?
Rotor Material	Copper	Aluminum	Copper	Copper	?
Winding Material	Copper	Copper	Copper	Copper	?
MinimumTemperature(C)	0	-18	-24	0	?
MaximumTemperature(C)	40	40	40	40	40
Temperature Rise(C)	80C@1.15	80C@1.0	90C@1.15	80C@1.0	80C@1.15
Sound Level		90dBA@1 meter	90dBA@2 meter	80dBA@1mete r	95dBA@1meter
Efficiency (1/2 Load)		91.5	94.5	92.8	91.7
Efficiency (3/4 Load)		92.7	94.8	94	92.8
Efficiency (Full Load)		93	94.8	94.3	92.9
Power Factor (1/2 Load)		68	70	73	75
Power Factor (3/4 Load)		78	79	81	82
Power Factor (Full Load)		82	82.5	84	84
Full Load Operating Torque	4670	4746	4730	4712	4764
Lock Rotor Torque (Starting)	8160	8543	8160	8160	10,242
Pull-UpTorque	7140	7356	7140	7140	8337
BreakdownTorque	8160	8543	8160	8953	11,195
Starting Duty (First Hr/After)	4(20 min)/1(Hr)	2 Cold/ 1 Hot	4(20 min)/1(Hr)	4(20 min)/1(Hr)	?

Table 3 - Technical Requirements Comparison (cont. page 4)

MANUFACTURER	Reliance	Westinghouse	Siemens	Toshiba	Ansaldo
Model	N/A	World Series	FODS	N/A	CT500W8
Rated Speed	888	885	892	890	887
Horsepower	800	800	800	800	800
Service Factor	1.15	1.15	1.15	1.15	1.15
Full Load Current	63.9	71	63.9	67	67.7
Locked Rotor Current (%)	709	631	624	650	581
Enclosure Type	TETC	TEAAC	WPII	TEFC	TEAAC
Frame	9500	5012SPC	3023	N/A	500
Insulation Class	F-VPI	F	F-VPI	F	F
Rotor Construction	Double Cage	Single Cage	Double Cage	Double Cage	Single Cage
Rotor Material	Copper	Copper	Copper	Copper	Aluminum
Winding Material	Copper	Copper	Copper	Copper	Copper
MinimumTemperature(C)	-25	0	-40	0	0
MaximumTemperature(C)	40	40	40	40	40
Temperature Rise	85C@1.0	90@1.15	80@1.15	80@1.0	90C@1.15
Sound Level	88dBA@2 meters	90dBA@2meter	82dBA@2 meter	90dBA@2 meter	85dBA@1 meter
Efficiency (1/2 Load)	91.6	92.6	94.8	91	91.7
Efficiency (3/4 Load)	92.9	93.6	94.9	93	93.1
Efficiency (Full Load)	93.2	93.6	94.5	94	93.5
Power Factor (1/2 Load)	75.6	61.2	77.8	70	71
Power Factor (3/4 Load)	84.1	72.6	84.4	79	80
Power Factor (Full Load)	87.7	78.1	86.5	83	83
Full Load Operating Torque	4737	4744	4710	4721	4735
Lock Rotor Torque (Starting)	9032	11,175	4239	8498	11,100
Pull-Up Torque	7819	11,175	4239	7081	8500
Breakdown Torque	14554	13,188	10126	9442	13,960
Starting Duty (First Hr/After)	?	4(20 min)/1(Hr)	?	2 cold/ 1 hot	4 cold/ 2 hot

Table 3(cont.) - Technical Requirements Comparison

Starting Current Limitations

The specifications required a maximum starting current of 650% of rated full load current. This requirement was based on the intent to minimize momentary reductions in voltage on the small motor bus and to limit starting forces on the motor. Reliance proposed a motor which had a starting current of 710%. In addition, Reliance proposed a motor which was too tall for the existing location and did not provide complete information to evaluate their bid. Reliance was eliminated as an acceptable bidder.

Rotor Cage Construction and Design

The specifications required the rotor cage to be fabricated out of a copper alloy with a double bar squirrel cage design. Four of the bidders proposed double cage designs while the remaining bidders proposed single cage designs. The specification for double cage design was based on the ability of the existing motor rotors to survive under extremely high and intermittent torque loading. Since the majority of bidders verified the torque capability of their proposed motors either design is considered acceptable.

Two bidders proposed fabricated aluminum rotor cages. In general, we do not believe aluminum provides the same strength as copper alloy rotor cages under high cyclic loading. In order to accept fabricated aluminum we would require at least five years of utility motor experience in pulverizer applications to accept this alternative. The apparent low bidder Ansaldo/Ross Hill was requested to provide a list of motors users to verify this experience. We could not determine from their lists a large number of motors in utility applications for crushers/pulverizers which were similar to the motor they proposed to provide. The bids from Ansaldo/Ross Hill and General Electric were eliminated based on noncompliance with the specifications.

Temperature Rise

The specifications required a maximum of an 80 C rise over an ambient of 40 C at the rated service factor load. This requirement was added to provide additional thermal margin under severe operating conditions (maximum service factor load with high ambient temperature conditions). Almost all bidders took exception to this requirement. With the exception of Siemens and Reliance, all other bidders proposed providing motors with the NEMA standard Class B temperature rise of 90 C over an ambient of 40 C at the service factor. This exception is considered acceptable because we believe we have provided sufficient thermal margin in requiring the motor to have Class F insulation but limiting the design temperature rise to Class B.

Enclosure Type

The existing motors provided by Siemens are listed as totally enclosed fan cooled (TEFC) motors. In accordance with the current NEMA descriptions they should probably be classified as totally enclosed air-to-air cooled (TEAAC) motors. Although the specifications required TEFC motors almost any type of totally enclosed motor would be acceptable (TEFC, TEAAC or totally enclosed tube type (TETC)). The specifications required these motors to operate in environments subject to coal dust and washdown and we believe a totally enclosed motor is required to provide sufficient protection for the motors. Siemens proposed a weather protected (WPII) motor because of their ability to match a current Siemens design with the existing motor dimensional requirements. We do not consider this enclosure acceptable and eliminated Siemens from the bid list.

Bearing Type

Toshiba proposed using anti-friction bearings in lieu of the specified sleeve type bearing to better match the existing motor dimensional requirements. While we believe that anti-friction bearings are useful in specific applications, sleeve type bearings are generally preferable in this motor of this size because of the infinite service life of sleeve bearings when the bearings are designed, installed and maintained correctly. In this particular case we believe there exists severe intermittent loading on the motor bearings, during normal operation, because of the design of the pulverizer and pulverizer gear boxes. For this reason we do not consider anti-friction bearings to be acceptable. We removed Toshiba from the list of acceptable motor manufacturers for this motor.

Starting Duty

Several motor manufacturers took exception to the requirement for four starts equally spaced (every 20 minutes) the first hour and then one start every hour thereafter. They almost exclusively proposed 2 cold starts or one hot start which is the basic NEMA standard. In general, they were willing to consider additional starts if a speed torque (load) curve was furnished by the pulverizer manufacturer. Babcock and Wilcox has been unwilling or unable to provide a speed torque curve for the pulverizers. Babcock and Wilcox's standard motor specification for a MPS89G pulverizer requires four starts the first hour and one every hour thereafter. Motors which did not provide required starting information or acceptable starting information were eliminated from consideration.

Dimensional Requirements

Very few bidders provided detailed dimensional drawings as required by the specifications. Westinghouse did provide a detailed drawing and we are confident their motor would interchange with the existing pulverizer motors. Most manufacturers did mark-up standard prints with the critical dimensions furnished by the specifications. We have discussed dimensional compatibility requirements with TECO and they assure us they will send detailed drawings for approval before starting manufacturing. These drawings would be used to verify all of the critical dimensions on the proposed motor.

If there are problems with matching the TECO motor to the existing installation it may be necessary to purchase a Westinghouse motor at significantly increased cost.

Conclusion

The acceptable motor manufacturers are shown in Table 4.

PULVERIZER MOTOR EVALUATION SPECIFICATION 45180				
BIDDER	*Bob Green*	*Westinghouse*	*ABB*	*IRS*
MANUFACTURER	**TECO**	**Westinghouse**	**ABB**	**Magnetek**
Point of Manufacture	Tawain	Texas	Brazil	Wisconsin
Motor	$63,000	$93,117	$102,350	$128,333
Complete Test (Not Witnessed)	$4,066	$7,310	$0	$8,667
Complete Test (Witnessed)	$5,885	$12,676	$5,300	$13,000
Report (Duplicate Motor)	$1,926	N/A	N/A	N/A
Freight	included	$2,000	included	included
QA/QC Inspection	$2,500	$2,000	$3,500	$2,000
TOTAL COST (Complete Test)	$69,566	$104,427	$105,850	$139,000
TOTAL COST (Witness Complete)	$71,385	$109,793	$111,150	$143,333

Table 4 - Acceptable Bidders (Bid Cost Comparison)

The motor manufactured by TECO appears to meet the requirements of the specifications at the least cost. We are hesitant to recommend a motor which does not appear to have a proven track record in this type of application without increasing testing and warranty requirements. We feel strongly that IPSC Technical Services should witness the factory testing of this motor to verify compliance with the specifications and construction quality. In addition, IPSC should take advantage of the offer from TECO for a three year warranty. IPSC should also purchase one set of spare bearings at $8964 (not included in the cost comparison with other bidders).

IGS Black Trip Performance Data
1986 to 1987[1]

Revision 0, June 2007

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments
Jun 5, 1986	1	Overvoltage at ICS during testing				
Jun 7, 1986	1	Loss of all cooling tower fans while operating islanded				
Jun 7, 1986	1	Failure of switching surge capacitor ISY				
Jun 13, 1986	1	DC Bipole Block ACS error failed to open special earth ground switch				

IP12_005044

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments

Notes:

1. Includes black trips prevented by operation of scheme specifically installed to reduce risk of black trips.

2. MARS- Mona Auto Reclosure Scheme. Implemented June 1987.

3. RVARS - Residual Voltage Auto Reclosure Scheme. Implemented March 1987.

4. RATS - Reserve Auxiliary Transfer Scheme (PM 86). Tested Oct 1991.

IGS Black Trip Performance Data
1987 to Present[1]

Revision 7, June 2009

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments
Jan 87	U1	Conv. Trans. Sudden Pressure Relay - tripped Pole 1.(Pole 2 out of service). Contingency Arming trip signal to Unit 1 blocked because of incorrectly installed diode. Mona Lines trip on power flow relays (Unit operating at 840 MW -relays set at 600 MW).	Not Available	Not Available	Not Available	MARS/RVARS would have prevented black trip.
Feb 87	U1	Adelanto Conv. Trans. Sudden Pressure Relay trip Pole 1 (Pole 2 out of service) - Contingency Arming Trip Unit 1. VAR flow relays trip Mona lines. Damaged Circulating Water Crossover Piping, Water Box vent piping and auxiliary cooling piping.	Not Available	Not Available	Not Available	MARS/RVARS would have prevented black trip.
Apr 88	U1	Aux Trans 1A Sudden Pressure Trip caused by oil surge in line. Tieline Trip	Not Required	Not Required	Not Available	RATS would have prevented black trip.
Oct 88	U1	Pole 2 and Unit 2 out service for scheduled inspection and repair. ICS Operations washing down equipment in the Pole 2 PLC yard cause a phase to ground fault in the switchyard. Contingency arming trips Unit 1. Mona Lines trip on under voltage. **Black trip prevented by correct operation of MARS and RVARS.**	Correct operation	Correct operation	Not Available	Sequence event recorders show AC switchyard de-energized for 868 milliseconds.

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments
Nov 88	U1	Mona Line 1 tripped on B phase to ground fault. Ground current caused mis-operation of pilot wire and SPD relay tripped U1 Tieline.	Not Required	Not Required	Not Available	RATS would have prevented black trip.
Dec 88	U2	LCB Differential Trip (Relay Mis-operation ?) Tieline Trip	Not Required	Not Required	Not Available	RATS would have prevented black trip.
Jan 89	U1	Mona Line 2 tripped on phase to ground fault. Caused mis-operation of pilot wire and SPD relay tripped U2 Tieline.	Not Required	Not Required	Not Available	RATS would have prevented black trip.
Nov 89	U1	Unit 2 Tieline isolated for relay testing. Relay personnel tripped Unit 1 Tieline in error.	Not Required	Not Required	Not Available	RATS would have prevented black trip.
May 90	U1	Gen. Trans. Differential Trip caused by cut insulation on internal current transformer wires. Tieline Trip	Not Required	Not Required	Not Available	RATS would have prevented black trip.
Dec 90	U1	Gen Trans. Deluge Trip. Deluge valves frozen and leaking. Unit tripped by personnel trying to isolate deluge system. Tieline trip.	Not Required	Not Required	Not Available	RATS would have prevented black trip.
Mar 91	U2	Contingency arming initiated a Unit 2 (Unit 1 and Pole 2 out of service) trip because of DC Line derivative protection operation. Generator Circuit Breaker failed to open in 9 cycles causing a breaker failure operation and a Tieline trip.	Not Required	Not Required	Not Available	RATS would have prevented black trip. Gen CB breaker failure protection setting too close to operating time limit of breaker-changed to 15 cycles

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments
Nov 93	U1	AC Switchyard Bus 2 isolated for testing. Relay personnel accidentally tripped Bus 1.	Not within design scope	Not within design scope	Not within design scope	Procedural changes implemented to prevent accidental tripping of tieline.
Jan 94	U1,U2	Large frequency deviation caused by earthquake. Frequency swings cause the DCPSC to turn off and constant frequency controller (CFC) to turn on. CFC ramps load on DC lines to maximum limit. Mona Line 1 trips on negative sequence current. MARS immediately recloses and energizes the line. Less than 0.5 seconds later, power flow relays trip both Mona lines because of increased load. MARS reclosure of Mona Line 1 is blocked because of built in 40 second time delay. MARS reclosure of Mona Line 2 is blocked because of a failed power supply (power supply had failed three days earlier). Units trips on under frequency. RVARS starts sequence, tripping Poles and AC Filters but can not complete sequence with Mona Lines de-energized.	Reclosed Mona Line 1 but could not reclose after line re-opened. Reclosure of Mona Line 2 blocked because of a failed power supply.	MARS failure blocked complete operation of RVARS.	Not within design scope	Convertor Station controls modified and generator frequency time setting changed from 1 to 4 seconds.
Jul 94	U2	Aux trans B deluge system operated. Tieline tripped. **Black trip prevented by correct operation of RATS.**	Not Required	Not Required	Correct operation	One of 6900 volt circuit breakers failed to operate correctly.

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments
Dec 94	U1,U2	Large frequency deviation caused by WSCC disturbance. Frequency swings caused the DCPSC to turn off and constant frequency controller (CFC) to turn on. CFC ramps load on DC lines to maximum limit. Power flow relays trip Mona lines because of increased load. MARS recloses breakers at Mona and re-energizes lines. High voltage at Mona causes large VAR flow over the Mona lines. Mona lines immediately trip due to VAR flow relays. MARS is blocked from a second reclosure because of a built in 40 second time delay. Units trip on under frequency. RVARS starts sequence, tripping Poles and AC Filters but can not complete sequence with Mona Lines de-energized	Reclosed but tripped again due to VAR flow relays at Mona.	MARS failure blocked complete operation of RVARS	Not within design scope	Convertor Station controls modified and generator under frequency time setting changed from 1 to 4 seconds.
Mar 96	U1	LCB relay in alarm. Relay personnel troubleshooting when a trip signal is sent tripping Tieline. **Black trip prevented by correct operation of RATS.**	Not Required	Not Required	Correct operation	
Jul 96	U2	Aux trans A deluge system operated. Tieline tripped. **Black trip prevented by correct operation of RATS.**	Not Required	Not Required	Correct operation	

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments
Jan 98	U2	Breaker Failure Relay (50BF) failed due to a bad connection on the 'B' phase generator bushing current transformer. The breaker failure relay was removed from the relay case and the unit brought off line to investigate the current transformer problem. Because the relay was removed from the case the trip circuit was enabled and when the unit tripped on reverse power (normal shutdown) the switchyard circuit breakers were tripped. **Black trip prevented by correct operation of RATS.**	Not required	Not required	Correct operation	
Apr 01	U1	Switchyard side potential transformer fuses were not installed before the generator step-up transformer was energized. An attempt was made to install the fuses but the tie-line tripped due to voltage unbalance. **Black trip prevented by correct operation of RATS.**	Not required	Not required	Correct operation	

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments
Jan 03	U1	Aux trans B deluge system operated. Tieline tripped. **Black trip prevented by correct operation of RATS.**	Not required	Not required	Correct Operation	The A2 circuit breaker (cubicle 0) did not close because it had been racked too far into the cubicle and did not make its limits. The B2 circuit breaker (cubicle 0) closed and carried current but it overheated because the 'B' phase connection bolt was loose. The bolt carried the current instead of the contacts.

Date	Unit	Description	MARS[2]	RVARS[3]	RATS[4]	Comments
Mar 30, 2003	U1	Generator Step-Up transformer deluge valve mis-operated during routine maintenance (draining). Deluge system actuated transformer lockout relay. **Unit tripped black except for loads on the 1B1 bus.**	Not required	Not required	Controls operated correctly	The 1A1,1A2 and 1B2 circuit breakers (cubicle 0) were given a close command but did not close because they had been racked too far into the cubicle. The breakers were latched into the mechanical trip position. The 1B1 circuit breaker closed correctly.
Sept 28, 2008	U2	Unit tieline differential protection LCB, 87L, initiated a tieline trip. Switchyard 87L relay did not trip, as shown by relay trip indicating light. Switchyard circuit breakers (9-2 and 9-3) tripped by transfer trip function. **Black trip prevented by correct operation of RATS.**	Not required	Not required	Correct Operation	
Jun 23, 2009	U2	Generator Circuit Breaker faulted on the 'B' phase. GCB not available because of loss of control air. The breaker failure scheme operated and tripped the tie line. **Black trip prevented by correct operation of RATS.**	Not required	Not required	Correct Operation	

Notes:

1. Includes black trips prevented by operation of scheme specifically installed to reduce risk of black trips.

2. MARS- Mona Auto Reclosure Scheme. Implemented June 1987.

3. RVARS - Residual Voltage Auto Reclosure Scheme. Implemented March 1987.

4. RATS - Reserve Auxiliary Transfer Scheme (PM 86). Tested Oct 1991.

Bottom Ash Transfer Pump Motors

Initial Installation

Unit 1		Unit 2	
1A1	215	1A1	248
1A2	216	1A2	249
1B1	217	1B1	250
1B2	218	1B2	251

Motor History

217 scrapped in June 1997 after 11 ½ years of service, two bearing changes. Catastrophic bearing failure leading to winding damage

248 scrapped October 1999 after 14 years of service, two bearing changes, failed motor lead and one catastrophic bearing failure requiring a rewind. Catastrophic bearing failure leading to winding damage.

249 scrapped September 1999 after 14 years of service, three bearing changes. Catastrophic bearing failure leading to winding damage.

Before the motor data base the Unit 2 1B2 motor was replaced after two years of service.

Serial 215

03/90	Bearing failure (broken mounting feet)		$3053
12/90	reinstalled		
12/93	bearing failure		$1117
4/94	reinstalled		
12/94	winding failure (pump problems)		$3735
1/95	reinstalled		
8/96	bearing change (onsite)		
1/97	bearing change (onsite)		
6/99	bearing change (onsite)		
10/01	bearing change (and mechanical work)	estimated	$3533+

Intermountain Power Project
General Electric Bushings

Unit 1 Generator Step-Up Transformer

	Description	Serial Number H3	Serial Number H2	Serial Number H1
H Winding	GE Type "U" 345 kV 1600 A	11B925BB G1 1792503 C_1 317 pf.30	11B925BB G1 1792502 C_1 318 pf .30	11B925BB G1 1792501 C_1 319 pf .30
X Winding	GE Type "T" 25 kV 21500 A	1791317 C_1 1243 pf.21	1791316 C_1 1364 pf .22	1792288 C_1 1260 pf .24
X_O	GE Type "U" 46 kV 1200 A	17B402BB G1 2159704	Not Applicable	Not Applicable

Unit 1 Auxiliary Transformers

Unit 1A

	Description	Serial Number	Serial Number	Serial Number
H Winding	GE Type "U" 23 kV 2000A	17B250BB G1 2159704	17B250BB G1 2159705	17B250BB G1 2159711
X Winding	GE Type "A" 23 kV 3000 A			
Y Winding	GE Type "A" 23 kV 3000 A			
X_O,Y_O	GE Type "U" 23 kV 1200 A	7B522BB G14 2158390	7B522BB G14 2158389	Not Applicable

Unit 1B

	Description	Serial Number	Serial Number	Serial Number
H Winding	GE Type "U" 23 kV 2000A	17B250BB G1 2159710	17B250BB G1 2159709	17B250BB G1 2159708
X Winding	GE Type "A" 23 kV 3000 A			
Y Winding	GE Type "A" 23 kV 3000 A			

X_O, Y_O	GE Type "U" 23 kV 1200 A	7B522BB G15 2176778	7B522BB G14 2159359	Not Applicable

Unit 1 Reserve Auxiliary Transformers
RAT 1C

Unit 2 Generator Step-Up Transformer

H Winding	GE Type "U" 345 kV 1600 A Cat # 11B925BB-G1	H1 - S/N 1796137 Manufactured 1985 C_1 350 pf 0.27 C_2 5084 pf 0.350	H2 - S/N 1796138 Manufactured 1985 C_1 352 pf 0.27 C_2 5568 pf 0.298	H3-S/N 1795969 Manufactured 1985 C_1 322 pf 0.26 C_2 5740 pf 0.249
X Winding	GE Type "T" 25 kV 21500 A	X1 - S/N 1791847 Manufactured 1984 C_1 1276 pf 0.22	X2 - S/N 1792287 Manufactured 1985 C_1 1295 pf 0.24	X3 - S/N 1791844 Manufactured 1984 C_1 1249 pf 0.23
X_O	GE Type "U" Class HTL46H 46 kV 400/1200 A Cat# 17B402BB-G1	S/N 1791843 Manufactured 1984 C_1 335 pf 0.32	Not Applicable	Not Applicable

Unit 2 Auxiliary Transformers
Unit 2A

	Description	Serial Number	Serial Number	Serial Number
H Winding	GE Type "U" 23 kV 2000A			
X Winding	GE Type "A" 23 kV 3000 A			
Y Winding	GE Type "A" 23 kV 3000 A			
X_O, Y_O	GE Type "U" 23 kV 1200 A			Not Applicable

Unit 2B

	Description	Serial Number	Serial Number	Serial Number
H Winding	GE Type "U" 23 kV 2000A A			

X Winding	GE Type “A” 23 kV 3000 A			
Y Winding	GE Type “A” 23 kV 3000 A			
X_O,Y_O	GE Type “U” 23 kV 1200 A			Not Applicable

Unit 1 Reserve Auxiliary Transformers
RAT 1C

	Description	Serial Number	Serial Number	Serial Number
H Winding	Westinghouse Type O+C Style 069W041ZAN Cat# W17B600BB Max L-G 44 kV	H1 - S/N 3053770390 C1 270 pf .24		
X Winding	GE Type “A” 23 kV 3000 A			
Y Winding	GE Type “A” 23 kV 3000 A			
X_O,Y_O	GE Type “U” 23 kV 1200 A			Not Applicable

Coal Car Thaw Shed Transformers

	Description	Serial Number	Serial Number	Serial Number
H Winding	GE Type “U” Cat 17B400BB 46 kV 1200 A			

X Winding	GE Type "A" Cat 1B496BB 2.5 kV 6000A			
X_O	GE Type "A" Cat 1B496BB 2.5 kV 6000A		Not Applicable	Not Applicable

	Description	Serial Number	Serial Number	Serial Number
H Winding	GE Type "U" Cat 17B400BB 46 kV 1200 A			
X Winding	GE Type "A" Cat 1B496BB 2.5 kV 6000A			
X_O	GE Type "A" Cat 1B496BB 2.5 kV 6000A		Not Applicable	Not Applicable

Construction Power Substation Transformers

North Substation

	Description	Serial Number	Serial Number	Serial Number
H Winding	GE Type "U" Cat 17B400BB 46 kV 1200 A			
X Winding	GE Type "A" Cat 1B679BB 15 kV 600A			
X_O	GE Type "A" Cat 1B679BB 15 kV 600A		Not Applicable	Not Applicable

South Substation

	Description	Serial Number	Serial Number	Serial Number

H Winding	GE Type "U" Cat 17B400BB 46 kV 1200 A			
X Winding	GE Type "A" Cat 1B679BB 15 kV 600A			
X_0	GE Type "A" Cat 1B679BB 15 kV 600A		Not Applicable	Not Applicable

Spares

Stock Number	Description	Serial Number	Serial Number	Serial Number
042750	17B250BB G1	2176767	2176794	2176783

Notes:

Unit 2 Generator Step-Up Transformer neutral bushing replaced under WO 89-03691.
Unit 1 Generator Step-Up Transformer X1 bushing replaced under WO 91-87396
Unit 2 Generator Step-Up Transformer neutral bushing replaced under WO 95-77449.
Unit 1B Auxiliary Transformer west side neutral bushing replaced under WO 97-86262.
Unit 2A Auxiliary Transformer both neutral bushings replaced under WO 98-06257

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: George W. Cross

FROM: Dennis K. Killian

DATE: April 9, 2001

SUBJECT: Transformer Bushing Monitoring System

During the Unit 1 Spring 2001 Outage a continuous bushing monitoring system was installed on the generator step-up and auxiliary transformers (high side bushings only). This system monitors the insulation quality of the bushings and provides an alert when the bushing insulation starts to deteriorate.

This system is connected, by modem, to a server at the Doble Engineering Company and is checked on an hourly basis for alarms or failures. Doble has been instructed to notify the Control Operator if they receive indication of any significant problems with the transformer bushings. They will also notify the Control Operator if the system fails to operate correctly. Please have the electricians troubleshoot any system failures and notify Engineering Services of any alarms which are received.

Typically bushing insulation degradation does not occurs rapidly. We do not expect Doble to contact the Control Operator unless the system fails to communicate correctly. Doble will provide Technical Services with monthly reports on the bushing insulation system. These reports will be used to trend the bushing condition and provide advance warning of any bushing problems.

Please find attached a brief description of the Doble Bushing Monitoring System. If you have any questions or concerns please contact Jon P. Christensen at Extension 6481.

cc :

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: S. Gale Chapman

FROM: Dennis K. Killian

DATE: July 5, 1996

SUBJECT: Unit 1 Generator 'B' Phase Bushing Failure

We recommend temporarily repairing the cracked Unit 1 'B' Phase Bushing by removing the existing viscasil sealant and replacing it with a layer of GE RTV 11 and a layer of viscasil. This work will require removing the unit from service, purging the generator and opening the generator bushing box. Actual repair time is estimated to be 36 hours (includes 24 hours cure time).

Until this repair can be performed, we recommend the following actions be taken to minimize the risk of operating the generator while the bushing is leaking hydrogen.

- Monitor and record hydrogen leakage at the failed bushing twice per shift.
- Monitor the size of the viscasil® puddle.
- Perform generator hydrogen consumption testing twice a week.

If the leakage rate increases significantly the unit should be removed from service and repaired. If the leak stabilizes at the current levels the leak should be repaired during the next available outage window. There is limited risk from continuing to operate with the current leakage rates unless the hydrogen is allowed to accumulate to explosive levels.

Detailed Analysis

The Unit 1 Generator 'B' Phase Bushing was replaced in April 1995 because of a crack in the bushing. The epoxy cement forming the primary hydrogen seal had failed (see attached drawing GEK-7658). This allowed the secondary seal consisting of a viscous sealing compound (viscasil®) to leak from the bushing box to the current transformer mounting plate. Because the viscasil® seal contained the internal hydrogen pressure in the generator no significant increase was noted in the generator hydrogen consumption before the leak was repaired.

In June 1996 hydrogen consumption for the Unit 2 Generator increased from 457 cubic feet per day to 1573 cubic feet per day. This increase in hydrogen consumption was accompanied by viscasil® leaking from the Generator 'B' Phase Bushing. A visual inspection of the bushing showed a crack at the porcelain seal area with viscasil® dripping out of the crack onto the current transformer support plate. Hydrogen was detected at the crack but dissipates within three inches of the crack to almost non-detectable levels.

We have discussed this failure with General Electric (GE) and Mechanical Dynamics and Analysis (MD&A). Both feel there is minimal risk in continuing to operate with the cracked bushing as long as we can maintain the hydrogen concentrations below explosive limits. GE recommends we replace the bushing as a permanent repair and perform modal testing to determine the failure mechanism. They are presently evaluating short term repair options. MD&A described a temporary repair procedure using GE RTV 11 as a primary seal and viscasil® as a secondary seal. A copy of the specification for RTV 11 is attached.

We recommend performing the temporary repair using RTV 11 during the next available outage window or if leakage rate increases. Maintenance should order viscasil® and RTV 11 and prepare to re-seal the bushing.

We will provide a recommendation for a permanent repair as soon as we have completed our evaluation. If you require further information please contact Jon P. Christensen at Extension 6481.

JPC:JHN
Enclosures

cc: Robert A Davis
    Joe D. Hamblin

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: Joe D. Hamblin

FROM: Dennis K. Killian

DATE: October 16, 1996

SUBJECT: Unit 1 Generator Bushing Repair

We recommend temporarily repairing the Unit 1 Generator 'B' Phase Bushing by using the GE Magic Dust Procedure during the short October 1996 Outage. A copy of the procedure is attached for your review.

This procedure should be modified to include a measurement of the existing layer of viscasil® before the annulus between the bushing and the terminal plate is cleaned. After cleaning, the bushing should be thoroughly inspected to determine if the crack has propagated above the annulus. If necessary, a temporary dam should be installed around the bushing to increase the depth of the viscasil®.

We have discussed installing a temporary dam with GE and they are presently preparing a design package for this installation. Please order the parts through the Salt Lake Office of GE and have the parts available for this outage.

Technical Services will provide quality assurance for the work during the October Outage. We are still investigating the bushing failure mechanism and we will provide additional information for the bushing replacement scheduled for the April 1997 Outage. If you have any questions or require additional information please contact Jon P. Christensen at Extension 6481.

JPC:JHN

Enclosures

cc: S. Gale Chapman
Robert A. Davis
Dave Hawk

7200 Volt Distribution System Design Philosophy

By design, one auxiliary transformer supplies two lineups of 6900 volt switch gear. Unit Auxiliary Transformer 1A supplies Switchgear 1A1 and 1A2 and Unit Auxiliary Transformer 1B supplies Switchgear 1B1 and 1B2. Each line up of switchgear was designated as a small motor bus or a large motor bus. The 1A1 and 1B1 switchgear are small motor buses while the 1A2 and 1B2 buses are large motors buses. The small motor buses supply power to almost all of the secondary unit substations (SUS's) and to motors less than 1000 HP. The large motor buses supply power to all of the motors over 1000 HP, some small motors, and to the cooling tower SUS's.

Because the large motor buses supply loads with a higher total current requirement they operate at lower voltages than the small motor buses. The original design engineering firm, Black and Veatch, compensated for the expected lower operating voltages, on the large motor bus, by requiring all of the large motors to be designed to operate with rated voltages of 80% to 110% . However, some of the motors purchased as part of the equipment packages were provided with operating ranges of 90% to 100% of rated voltage. The air compressor motors and pulverizer motors fall into this category. Although the motors are provide with different voltage operating ranges performance characteristics (losses, power factor and efficiency) are all based on the rated voltage.

Rated motor voltage is based on system supply voltage. For a 6900 volt system motors are specified with a rated voltage of 6600 volts. This voltage differential compensates for line losses between the motor terminal and the source. The drop in voltage is especially significant during motor starting when the motor inrush current is normally 6 to 8 times rated current. Generating station high voltage motors were all specified with a nominal rating of 6600 volts.

The auxiliary transformers have 26 kV delta connected primaries with dual 7.2 kV wye connected secondaries. They were provided with a single set of tap changers on the primary side. Two 2 1/2% taps were provide above and two 2 1/2% taps below rated voltage. Because the taps were provided on the primary connection of the transformer, changing the taps affects both secondary windings and changes the voltage on both a large and small motor bus.

Operating Experience

During start-up the auxiliary transformers were set on tap position number three to provide the best operating range for the 6900 volt bus from minimum unit load to full unit load of 840 MWg. This tap setting provided a average bus voltage of 7000 volts on the small motor bus and 6750 volts on the small motor bus.

Subsequently two problems were identified with the existing operating voltages on the 6900 volt bus . First, the pulverizer motors, which are installed on the small motor bus, developed a heating problem. Generally, the motors for the generating station were specified to have Class F

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insulation with a Class B temperature rise. Class F insulation allows operation at up to 160 C (40 C ambient with a 120 C temperature rise) with no loss of life. By limiting the motor operating temperatures to a Class B temperature of 120 C (40 C ambient with a 80 C temperature rise) motor insulation life is extended. Specifying a Class F insulation with a Class B rise builds in a safety margin to compensate for the variability of operating conditions and for differences between calculated load requirements and actual load requirements.

The pulverizer motors were specified to have an 80 C rise (120 C total temperature) and yet over time they began to operate between 140 to 150 C. Testing by the motor manufacturer indicated the problem was partially caused by the motor operating voltage. Operating a motor above nameplate voltage causes higher magnetizing currents within the motor and increases motor heater . Our testing indicates operating the pulverizer motors at 7000 volts increases motor temperatures by 6 to 8 C.

Degradation of the internal cooling system and RTD measurement errors caused the rest of the temperature rise. The cooling system problems were corrected and the motors continued to operate with in the 130 C to 140 C range under high ambient temperature and maximum load conditions.

The second problem associated with bus voltages was caused by duplicate motors being operated on different type buses. The A, B and C air compressor motors are installed on small motor buses while the D air compressor is installed on a large motor bus. All of the timed over current relays, for the air compressor motors, were originally set based on rated voltage. Because the 'D' air compressor motor was installed on a large motor bus, with a lower operating voltage, it frequently tripped during starting. Our testing showed the motor current was just starting to return to normal levels when the motor over current relays tripped the supply circuit breaker.

Motor starting current is typically 6 to 8 times full load current. When a motor is started, this higher current level lasts until the motor is accelerated from standstill to near rated speed. The time required to accelerate a motor from standstill to rated speed is called acceleration time and is a function of the accelerating torque. Accelerating torque is a function of the difference between motor torque and the torque of the load. Since motor torque is a function of motor current and current is proportional to voltage, lower operating voltages increase the time required to accelerate a to rated speed. The longer it takes a motor to reach rated speed the longer the motor current stays at higher levels. Higher current levels cause increased winding temperatures and raise the possibility of damaging the windings.

Protective relays are set to trip the power circuit to motors if the starting current does not decrease to normal levels within the time frame specified by motor manufacturers. Since the 'D' compressor motor required more time for the starting current to decay to normal values it would frequently trip during starting. The motor protective relay settings were changed to compensate for the longer starting times. These changes were within the motor manufacturers recommendations. After the changes were made the D air compressor motor no longer tripped during starting.

Current Operating Status

When the generator output was increased from 840 MWg to 875 MWg the load increased on the auxiliary buses resulting in a slight lowering of the auxiliary bus voltages. Typically the large motor bus now operates at 6600 volts and the small motor bus operates at 6900 volts. Typical bus conditions are shown in Table 1.

Unit 6900 Volt Switchgear Operating Conditions (Unit load at 875 MWg)		
Switchgear	Voltage	Current
1A1	6950	1000
1A2	6600	1800
1B1	6900	900
1B2	6600	1725
2A1	6850	800
2A2	6600	2000
2B1	6900	800
2B2	6600	1650

These values vary depending on which equipment is in service, but generally the large motor buses are running 150 volts less and the small motor buses are running 50 to 100 volts less.

The lower bus voltages caused the 'D' air compressor motor to begin tripping again during starting. Once again the protective relays were reset to provide longer starting times. This setting was changed to the recommended maximum recommended by the motor manufacturer.

The lower bus voltages helped reduce the operating temperature of the pulverizer motors due to increased magnetizing current. But, other operating changes (poor quality coal, increased quantities of rocks, etc) have offset the temperature reduction and the motors now operate in the 150 to 160 C range during worst case conditions.

Ideally the load on the 6900 volt bus should be more balanced to provide more equal voltages between the large and small motor buses. In addition, the 'D' air compressor motor should be moved to the small motor bus.

FAX

T R A N S M I T T A L

IPP

INTERMOUNTAIN POWER SERVICE CORPORATION

ADDRESS: 850 W. Brush Wellman Rd., Delta, UT 84624
CONFIRMATION: (435) 864-4414 Ext. 6577
FACSIMILE: (435) 864-6670

TO

Company: ____________________
Attention: John Fitzgerald
Facsimile: 313-640-9419.

FROM

Name: Jon P. Christensen
Department: Technical Services
Phone: 435-864-6481
Date: January 7, 2011

Pages to follow: __________

Comments:
Please find attached the items we discussed on the cathodic protection system at the Intermountain Power Project:
1) Overview of the cathodic protection system for the condenser water boxes and auxiliary cooling water heat exchangers . (17 pages)
2) Circulating water piping system cathodic protection system test procedure (2 pages)
3)Test cell information for circulating water piping system cathodic protection (4 pages)
4)Cathodic protection system for underground storage tanks. (4 pages)
5) Map to the plant from the Salt Lake City airport. (1 page) Exit the airport and take I-80 west . Take the Tooele exit off of I-80. Drive through Tooele and stay on Highway 36 until it intersects with Highway 6. Turn right on Highway 6 and follow it until you see the sign for Brush Wellman Road. Turn right on Brush Wellman (the sign will also say Intermountain Power Project). Follow the road for 8 miles until you see the entrance to the plant on the right.
Please call me if you need any more information.

____
Approval

____
Date/Time Sent

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: S. Gale Chapman

FROM: Dennis K. Killian

DATE: January 4, 1996

SUBJECT: Generator Clip to Strand Repair

We recommend preparing for possibility of repairing clip to strand leaks on the generator stator bars by pre-qualifying vendors to perform these repairs. Vendors should be pre-qualified based on the following criteria.

- Experience- Shop and Field
- Independent Analysis of Repair Techniques and Actual Repair
- Technical Evaluation
- Demonstration of Repair Set-up and Installation
- Ability to Fabricate and Stock Repair Components

The qualifications of the three vendors known to be offering this repair are summarized in the following table.

	ABB	MD&A	Westinghouse
Experience	Shop Demonstration Scheduled to replace 144 clips (Alabama Power) 3/96	Shop Demonstration 28 clips Cedar Bayou and 6 clips Waco	Shop Demonstration None
Independent Analysis	Will install a new clip on IPP spare bar at no charge for analysis by others No other clip assemblies are available	Will install a new clip on IPP spare bar at no charge for analysis by others No other clip assemblies are available	

Technical Evaluation			
Demonstration	Single bar demonstration	Single bar demonstration Set a mock up of generator which includes top and bottom bar and all brazed connections	Single bar demonstration
Material	Scheduled to measure IPP bars on Feb 1, 1996	Can manufacture clips within 2 to 3 days after dimensions are available	

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: S. Gale Chapman

FROM: Dennis K. Killian

DATE: January 4, 1996

SUBJECT: Generator Stator Bar Clip-to-strand Repairs

We recommend implementing a testing program to pre-qualify vendors to perform clip-to-strand repairs on the generators. Although our online testing does not indicate leakage is increasing at the clip-to-strand connections on the generators we should be prepared to perform clip-to-strand repairs if required. Currently available repair technology offers significant improvements in reliability while minimizing repair costs. The final decision for repair should be based on outage testing such as our pressure/vacuum test.

Recently three separate vendors, ABB, MD&A and Westinghouse have introduced repair procedures which are more economical than rewinding the generator. These appear to be more reliable than the repair techniques recommended by General Electric. Because there has been limited actual experience with these repair methods, we recommend using the following procedure to pre-qualify vendors to perform this work at the Intermountain Generating Station.

<u>Generator Clip-to-strand Repair Vendor Pre-qualification Procedure</u>

1. Witness a strand to clip repair procedure at ABB. ABB will provide a written description of the quality assurance requirements before the repair is made. After ABB Send the repair to an independent lab to be tested using computer aided tomography (CAT) technology. After the CAT scan is complete, section the repair to determine if the results of the microscopic examination agree with the CAT scan. Based on the results of this test use CAT scans or destructive testing (microscopic examination) to inspect the repair of other vendors.

2. Send one of the spare top bars from IPSC to the other two vendors (one vendor at a time). Have the vendor remove the

existing clip and install a new clip. Review the vendors written description of the repair procedure and quality assurance requirements before the repair is made. Witness the repair procedure and note any deviations from the procedure or quality control problems. Note size and spacing of equipment required for the repair.

3. Inspect the repair using CAT scans or by microscopic examination of the clip.

4. Based on acceptable test results, vendors will be permitted to bid on repairs at the Intermountain Generating Station when outage testing indicates repairs are necessary.

Costs for this testing program are summarized in the table below.

		ABB	**MD&A**	**Westinghouse**
Step	Description			
I	Provide a sample clip-to-strand connection	No Charge IPSC Personnel Expenses $2000	No Clip-to-strand Connections are presently available	No Clip-to-strand Connections are presently available
IIa	Install a new clip on a spare bar from IPSC	Not Applicable Examination of a sample clip will be used to determine repair quality.	No charge for clip installation IPSC Personnel Expenses $2000 Shipping $50	$5000 for clip installation IPSC Personnel Expenses $2000 Shipping $50
IIb	Install a new clip on a spare bar from IPSC (If the bar is shipped whole)	Not Applicable Examination of a sample clip will be used to determine repair quality.	No charge for clip installation IPSC Personnel Expenses $2000 Shipping $4500	$5000 charge for clip installation IPSC Personnel Expenses $2000 Shipping $5200

IIIa	Test(Slice clip and microscopic examination) of clip on sectioned bar[1,2]	Test $2000 IPSC Personnel Expenses $2000 Shipping $50	Test $2000 IPSC Personnel Expenses $2000 Shipping $50	Test $2000 IPSC Personnel Expenses $2000 Shipping $50
IIIb	CAT Scan of clip on whole bar	Test $2500 IPSC Personnel Expenses $2000 Shipping $4500	Test $2500 IPSC Personnel Expenses $2000 Shipping $4500	Not Applicable

Note 1: This will require destroying one of the spare bars. The current value of our spare bars is estimated to be $16,500 each (current listed warehouse value $7,100). This estimated value includes the current price per bar, when several bars are ordered, and the cost to correct known deficiencies with our spare bars. Currently the three spare bars at the Intermountain Generating Station are of limited value because of the questionable clip construction and the limited quantity of bars in storage. Under normal conditions more bars would be ordered before attempting bar replacement because of the risk of damaging adjacent bars during bar removal.

Note 2: Under the option (steps IIa and IIIa) of destroying a spare bar only two vendors can be evaluated because only two clip-to-strand connections are available on one bar.

The total estimated cost for this test program if a spare bar is destroyed is $34,750 ($16,500 for the bar and $18,250 for testing). The cost if a complete bar is used is $22,000. The option of using complete bars is only feasible if CAT scanning is a viable technology.

In order to be prepared for the Unit 2 Spring 1996 this testing program will have to conducted expeditiously. A proposed schedule is attached for your review. The money for this testing program will come from the approved capital purchase of spare generator stator bars CEP95-25.

We recommend implementing this testing program because of the significant costs associated with a generator rewind or on-line failures. We should be prepared to correct leaks when they are discovered. During the past outages we have spent considerable time and money locating leaks and attempting repairs, recommended by GE, with little success. A significant part of the cost and time in finding leaks is required by our outage testing program. This testing is required to determine serviceability of the generator. We can minimize overall costs by performing repairs instead of returning the generator to service with known leaks or temporary repairs.

None of the proposed vendors have significant experience in performing their repair on existing machines. MD&A has recently installed their repair clips on two units. ABB is scheduled to replace all 144 clips on a generator in March of 1996. There is not enough operating experience with this repair technology to evaluate the integrity of the repair before our upcoming unit outages. Testing various repair methods will provide us with confidence in the vendors ability to repair our generators.

Please signify your authorization to proceed with this testing program by signing below.

If you have any questions or comments please contact Jon P. Christensen at Extension 6481.

Approved by________________________________Date________________

JPC:JHN
Attachments

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: S. Gale Chapman

FROM: Dennis K. Killian

DATE: January 4, 1996

SUBJECT: Generator Stator Bar Clip-to-strand Repairs

We recommend implementing a testing program to pre-qualify vendors to perform clip-to-strand repairs on the generators. Although our online testing does not indicate leakage is increasing at the clip-to-strand connections on the generators we should be prepared to perform clip-to-strand repairs if required. The available repair technology offers significant improvements in reliability while minimizing repair costs. The final decision for repair should be based on outage testing such as our pressure/vacuum test.

Recently three separate vendors, ABB, MD&A and Westinghouse have introduced repair procedures which are more economical than rewinding the generator and appear to be much more reliable than the repair techniques recommended by General Electric. Because there has been limited actual experience with these repair methods, we recommend using the following procedure to pre-qualify vendors to perform this work at the Intermountain Generating Station.

<u>Generator Clip-to-strand Repair Vendor Pre-qualification Procedure</u>

1. Witness a strand to clip repair procedure at Westinghouse. Westinghouse will provide a written description of the repair procedure and quality assurance requirements before the repair is made. Send the repair to an independent lab to be tested using computer aided tomography (CAT) technology. After the CAT scan is complete, section the repair to determine if the results of the microscopic examination agree with the CAT scan. Based on the results of this test use CAT scans or destructive testing (microscopic examination) to inspect the repair.

2. Send one of the spare top bars from IPSC to the other two vendors (one vendor at a time). Have the vendor remove the existing clip and install a new clip. Review the vendors written description of the repair procedure and quality assurance

requirements before the repair is made. Witness the repair procedure and note any deviations from the procedure or quality control problems. Note size and spacing of equipment required for the repair.

3. Inspect the repair using CAT scans or by microscopic examination of the clip.

4. Based on acceptable test results, vendors will be permitted to bid on repairs at the Intermountain Generating Station when outage testing indicates repairs are necessary.

Costs for this testing program are summarized in the table below.

Step		**ABB**	**MD&A**	**Westinghouse**
	Provide a sample clip-to-strand connection	No Clip-to-strand Connections are presently available	No Clip-to-strand Connections are presently available	No Charge IPSC Personnel Expenses $2000
	Install a new clip on a spare bar from IPSC (If the bar is sectioned)[1,2]	No charge for clip installation IPSC Personnel Expenses $2000 Shipping $50	No charge for clip installation IPSC Personnel Expenses $2000 Shipping $50	Not Applicable Examination of a sample clip will be used to determine repair quality.
	Install a new clip on a spare bar from IPSC (If the bar is shipped whole)	No charge for clip installation IPSC Personnel Expenses $2000 Shipping $3000	No charge for clip installation IPSC Personnel Expenses $2000 Shipping $2000	Not Applicable Examination of a sample clip will be used to determine repair quality.
	Test(Slice clip and microscopic examination) of clip on sectioned bar[1,2]	Test $2000 IPSC Personnel Expenses $2000 Shipping $50	Test $2000 IPSC Personnel Expenses $2000 Shipping $50	Test $2000 IPSC Personnel Expenses $2000 Shipping $50

	CAT Scan of clip on whole bar	Test $2500 IPSC Personnel Expenses $2000 Shipping $1000	Test $2500 IPSC Personnel Expenses $2000 Shipping $1000	Not Applicable

Note 1: This will require destroying one of the spare bars. The current value of our spare bars is estimated to be $16,500 each (current listed warehouse value $7,100). This estimated value includes the current price per bar, when several bars are ordered, and the cost to correct known deficiencies with our spare bars. Currently the three spare bars at the Intermountain Generating Station are of limited value because of the questionable clip construction and the limited quantity of bars in storage. Under normal conditions more bars would be ordered before attempting bar replacement because of the risk of damaging adjacent bars during bar removal.

Note 2: Under the option of destroying a spare bar only two vendors can be evaluated because only two clip-to-strand connections are available on one bar.

The total estimated cost for this test program if a spare bar is destroyed is $34,750 ($16,500 for the bar and $18,250 for testing). The cost if a complete bar is used is $22,000. The option of using complete bars is only feasible if CAT scanning is a viable technology.

In order to be prepared for the Unit 2 Spring 1996 this testing program will have to conducted expeditiously. A proposed schedule is attached for your review. The money for this testing program will come from the approved capital purchase of spare generator stator bars CEP95-25.

We recommend implementing this testing program because of the significant costs associated with a generator rewind or on-line failures. None of the proposed vendors have significant experience with performing this repair on existing machines. MD&A has recently installed their repair clips on two units and ABB is scheduled to install new clips in March of 1996. There is not enough operating experience with this repair technology to evaluate the integrity of the repair before our upcoming unit outages.

If you have any questions or comments please contact Jon P.

Christensen at Extension 6481.

Please signify with your authorization to proceed with this testing program by signing below.

Approved by_______________________________Date_______________

JPC:JHN
Attachments

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: Joe D. Hamblin

FROM: Dennis K. Killian

DATE: March 6, 1996

SUBJECT: Generator Stator Leak Repair Vendors

We have completed our analysis of the current repair options for generator clip-to-strand leaks. Our review indicates the repairs offered by ABB and Westinghouse are conditionally acceptable. The repair procedure offered by Mechanical Dynamics and Analysis, Inc (MD&A) is not acceptable. The repair offered by General Electric was not completely evaluated because GE was unwilling or unable to provide a repaired clip for laboratory analysis. However, based on our understanding of the repair process offered by GE we do not consider it a long term repair and it is not acceptable.

The preliminary laboratory inspection, performed by Radian, indicates the repair procedure performed by ABB leaves some small voids in the front face of the strand bundle. The repair by ABB is only acceptable if they prevent the formation of voids by using thicker shims between strand columns and/or touching up the face of strand bundle by stick brazing. The repair procedure by Westinghouse is acceptable if they reduce the temperature of the strands (behind the clip) to less than 350 F by correcting the installation of their chill blocks. Because of previous temperature control problems, Westinghouse must be required to monitor strand temperature during their entire brazing process.

The report from Radian on the repair process offered by MD&A indicates there are significant voids left in the front face of the strand bundle. MD&A's process also reduces strand wall thickness past the clip into the strand package. Although the number of voids left in the MD&A repair are significantly less than the original design by GE there are still too many voids to be acceptable. We also question the structural integrity of the reduced strand wall thickness.

In the GE repair we question the long term reliability of the epoxy coating and the ability of the epoxy to withstand high temperatures caused by re-brazing the nipple back on the clip. We will continue to pursue acquiring a repaired clip from GE to perform a complete evalution.

We will forward a copy of the final report from Radian when it is received. In addition, we will continue to evalute these repairs, based on industry experience, and othe repairs as they become available. If you require additional information please contact Jon P. Christensen at Extension 6481.

JPC/JHN

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: Joe D. Hamblin

FROM: Dennis K. Killian

DATE: March 6, 1996

SUBJECT: Generator Maintenance Recommendations

We have completed our analysis of the epoxy repair offered by General Electric (GE). The laboratory analyis of the clip repaired by GE indicates this repair procedure is acceptable. Because the GE repair procedure is significantly less risky than the repairs being offered by the other vendors we recommend the repair of the Unit 2 Generator Stator Cooling Water Clips be peformed by GE.

We also recommend the inspection of the Unit 2 Generator be performed with the field in place using GE's Miniature Air Gap Inspection Crawler (MAGIC). Although we will not be able to take full advantage of the maintenance labor cost savings associated with deleting the labor necessary to remove the field and reinstall it beacuse other maintenance activities requires partial generator disassembly using MAGIC can be justified based on reduced unit downtime. For the purpose of economic analysis we used $7000 significant stick brazing. The repair procedure by Westinghouse is acceptable if they reduce the temperature of the strands (behind the clip) to less than 350 F by correcting the installation of their chill blocks. Because of previous temperature control problems, Westinghouse must be required to monitor strand temperature during their entire brazing process.

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JPC/JHN

INTERMOUNTAIN POWER SERVICE CORPORATION

☐ REQUISITION FOR CAPITAL EQUIPMENT

■ PURCHASE AUTHORIZATION FOR EXPENSE ITEMS

Purpose of Materials, Supplies or Services:

Determine whether repair technologies offered by Westinghouse, ABB and MD&A are acceptable to use in IPP generators.

Date:	
Req./PA No:	115163
P.O. No:	
Vendor:	
Terms:	
FOB:	
Ship Via:	
Conf. To:	

Suggested Vendor: Radian Corporation
PO Box 201088
Austin,Texas 78720-1088
Attn: Karen Fuentes

Account No. 6525-503
Work Order No.
Project No.

Qty	Unit	Noun / Description Adjective / Catalog # / Seller or Manufacturer	Unit Cost	Extension
1	Lot	Microscopic examination and testing of three generator		$
		water clip assemblies to determine quality of brazing		
		and adequacy of repair. Vendor shall section each clip		
		immediately in front of strand package. The front of		
		the strand clip interface shall be microscopically		
		examined to determine thickness and porosity of		
		brazing to strand surface. Vendor shall determine		
		quantity and size of voids located on surface of		
		strand bundle and any blockage of hollow strands. The		
		strand package shall then be sectioned at 1/4"		
		intervals and examined to determine size and quantity		
		of voids. All braze interfaces in the clip shall be		
		examined to determine integrity of the braze. Based on		
		the examination and research completed in Radian		
		TOTAL ESTIMATED COST		$

Remarks:

Delivery requested by [Date] 03-02-96 Originator Jon P. Christensen

Dept. Mgr/Supt. Date Station Manager Date Operating Agent Date

The Intermountain Power Project has six Westinghouse 1750 HP 6600 volt vertical induction motors used for condensate pumps. These motors were purchased under Shop Order # 1734CA (Customer Order No. 9255.63.2201.1; General Order No. KCLA34017).

We have experienced oil leakage on all of these motors. The oil appears to come from the lower bearing through the oil seal. This oil coats the windings. We have had to rewind one of the motors because the motor space heaters apparently ignited the oil soaked sound insulation.

Since that time we have removed the motors from service and verified the oil seal clearances are correct and steam cleaned the motors. We are once again experiencing significant leakage around the base of the motor.

In reviewing the drawings provided with the motors, we note there is a copper tube running from the seal to the oil level gauge. None of our motors were provided with this line. Please explain the purpose of the line. The seals were all provided with holes to connect this line. Should these openings be plugged if the lines are not being used.

Please review the shop drawing and determine the most likely cause of this oil leakage and what we should do to correct this problem. Call Jon Christensen at (801) 864-4414 extension 6481 with the results of your investigation.

The Intermountain Power Project has six Westinghouse 1750 HP 6600 volt vertical induction motors used for condensate pumps. These motors were purchased under Shop Order # 1734CA (Customer Order No. 9255.63.2201.1; General Order No. KCLA34017).

We have experienced oil leakage on all of these motors. The oil appears to come from the lower bearing through the oil seal. This oil coats the windings. We have had to rewind one of the motors because the motor space heaters apparently ignited the oil soaked sound insulation.

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Please review the shop drawing and determine the most likely cause of this oil leakage and what we should do to correct this problem. Call Jon Christensen at (801) 864-4414 extension 6481 with the results of your investigation.

MEMORANDUM

INTERMOUNTAIN POWER SERVICE CORPORATION

TO: S. Gale Chapman Page ____ of ____

FROM: Dennis K. Killian

DATE: May 14, 1993

SUBJECT: Air Compressor Motor Analysis

FILE: 01.12.02, 43.1801

Our perscrutation of the recent problems associated with the operation of the D air compressor motor indicates this motor should be sent to a factory authorized repair facility. We recommend the motor be sent to for a thorough examination and repair.

After lengthy discussions with Westinghouse LArge Motor Service we have identified the following repair/replacement options.

1. Purchase a new idetical motor from Weestinghouse. This woukd be a custom motor which wouls require retooling by Westinghouse because thety no longer manufacture this model.

2. Purchase a mechanically and electrically identical motor. This would provide us with a more efficeint design but would require stocking different bearings and renewal parts because they would nit match the other thre air compressors.

3. Send the motor to anothe repair shop for examination and possible repair. Westinghouse recoomends Eastern Electric in Salt Lake City or the There own shop in Houston, Texas.

File: 01.03.01
IGS91-28

BEB

Capital Project IGS91-28 PA Fan Performance Review

Attached is our analysis of the operating performance of the Primary Air Fans at the Intermountain Generating Station. We recommend changing the nameplate rating on these motors in accordance with a report provided by the motor manufacturer. The motor will be rerated to 5000/3200 HP.

Please review the attached report and approve this package by March 1, 1993. If you have any questions or require additional information please have your staff contact Jon P. Christenen at extension 6481.

SGC

JPC:JHN
Enclosures

DRAFT COPY OF PROJECT
LETTER IGS 91-28
JON CHRISTENSEN
U: DRIVE WP FILES
PA LETTER. LTR

IP12_005087

SUMMARY

Our analysis of the primary air fans indicate the most economical solution to reducing outage costs associated with single fan operation is to rerate the motors in accordance with recommendations provided by the motor manufacturer, Westinghouse Electric. Changing the nameplate rating of the motors from 4000/2100 HP to 5000/3200 HP will restore the capability of the Primary Air (PA) System to support unit operation at 500 MWg (60% maximum unit capacity) with a single fan in service. The existing electrical system is adequate to support this revision with revised protective relay settings.

PA FAN PERFORMANCE/
RELIABILITY STUDY — PART
OF IGS 91-28

JON CHRISTENSEN
U DRIVE
WP FOLDER
TITLE PAFANRT

The scope of ... iew of the
design and c ... (PA) Fans and
recommendat...

The origina... l during
contract ne... rs to provide
auxiliary p... pendix A-Black
and Veatch ... ary 22, 1992).
The two spe... d (PAM) motors
provided by ... any overload
capability.

Since start... above original
nameplate ... operation, to
maintain ac... This overload
operation h... pressures and
flows than ... he primary air
system and

The namepla... power, 302/183
amperes (Ap... a). We reviewed
the capabil... o determine if
the slight ... ul life of the
motor. West... erated at 10 to
15 amperes ... ithout loss of
useful li... ated September
14,1990). ... ating limits of
302/200 am...

In discuss... stinghouse they
said they ... gn analysis to
determine ... tors. We issued
a purchase ... gn analysis and
determine ... Westinghouse
determined the motor could be upgraded from 4000/2100 horsepower, 302/183 amperes 1.0 service factor to 5000/3200 horsepower, 380/265

SUMMARY

Our analysis of the primary air fans indicate the most economical solution to reducing outage costs associated with single fan operation is to rerate the motors in accordance with recommendations provided by the motor manufacturer, Westinghouse Electric. Changing the nameplate rating of the motors from 4000/2100 HP to 5000/3200 HP will restore the capability of the Primary Air (PA) System to support unit operation at 500 MWg (60% maximum unit capacity) with a single fan in service. The existing electrical system is adequate to support this revision with revised protective relay settings.

PROJECT DESCRIPTION

The scope of Capital Project IGS91-28 included a review of the design and operating performance of the Primary Air (PA) Fans and recommendations for correction of any deficiencies.

The original design of the PA fan motors was changed during contract negotiations to Westinghouse 2 speed motors to provide auxiliary power savings during normal operation (Appendix A-Black and Veatch cover letter on PA fan report dated January 22, 1992). The two speed Westinghouse Pole Amplitude Modulated (PAM) motors provided by Babcock and Wilcox did not include any overload capability.

Since startup, the motors have operated slightly above original nameplate values (183 amperes), during low speed operation, to maintain acceptable PA System performance levels. This overload operation has been required because of higher system pressures and flows than originally specified in the design of the primary air system and significantly lower fan efficiency.

The nameplate rating of the motors is 4000/2100 horsepower, 302/183 amperes (Appendix B-Westinghouse Induction Motor Data). We reviewed the capability of these motors, with Westinghouse, to determine if the slight overload condition would reduce the useful life of the motor. Westinghouse agreed these motors could be operated at 10 to 15 amperes above nameplate on a continuous basis without loss of useful life (Appendix C-Westinghouse letter dated September 14,1990). This review resulted in the existing operating limits of 302/200 amperes.

In discussing the capability of these motors with Westinghouse they said they would have to perform a detailed design analysis to determine the maximum rating available on these motors. We issued a purchase order to have Westinghouse perform a design analysis and determine the maximum capacity of the motor. Westinghouse determined the motor could be upgraded from 4000/2100 horsepower, 302/183 amperes 1.0 service factor to 5000/3200 horsepower, 380/265 amperes 1.15 service factor (Appendix D-Westinghouse report dated February 25, 1992).

Temperature rise of the stator winding when the motor is operating at 5000/3200 HP is still expected to be within allowable limits for class B insulation. Since rise is within class B, the thermal life of the insulation will not be reduced from design.

In addition, during performance testing of these fans we have been unable to achieve the original design capacity of 60% unit load with one fan, in high speed, (Appendix E-Black and Veatch Specification 62.3401 section) without exceeding the motor amperage rating.

Based on our performance testing (Appendix F-Performance Test 11/4-5/89) and acceptance testing with Babcock and Wilcox (Appendix G-Performance Test 1/18/89) the fans are not capable of providing a significant increase in fan capacity, in high speed, without exceeding the existing motor nameplate rating (302 amperes).

Review of the test data by the original equipment supplier, Babcock and Wilcox, indicates the specified margins on fan performance result in a fan efficiency that is unattractive in the normal operating range and extremely inefficient at high speed. They recommend a fan motor rated at 2700 HP at low speed. The recommended motor rerate will provide a motor rated at 3200 HP at low speed.

Testing with the fan manufacturer, Howden Sirocco, (Appendix H-Howden Sirocco Test Reports) indicates a single fan is currently only capable of 300 MWg (36% unit load) at either high or low speed operation. Maximum fan capacity was determined by increasing the load on the unit until the fan motor reached full nameplate amperage limits. Howden Sirocco indicates the additional horsepower available from low speed to high speed operation is lost because of inefficiencies associated with the position of the inlet vanes during high speed operation and because the fan is significantly less efficient than specified.

Other problems discovered during our review of the performance of the PA Fans were incorrect warning and absolute alarm levels for the motor stator temperature sensors (set at 180 C and 194 C) and an incorrect setting for the motor air filter differential switch. The motor stator alarms have been changed to the setting provide by Westinghouse of 130 C for warning and 135 C for absolute alarm.

The motor air filter differential air switch should be replaced with a model having a range .5 to 1.0 inches of water. The new switch should be set at .65 inches of water. The original setting of .35 is no longer valid because of modifications made to the air filters to provide for access without removing the motor from service.

Based on our review we compared the following options to determine the costs of outages associated with PA fan motor failures.

OPTIONS

1. Operate the PA Fans at the present limits of 200 amperes low speed and 303 amperes high speed. 300 MWg with single fan operation. (Base Case)

2. Change the wheel and vanes on the existing fans to provide for 500 MWg (60% unit capability) with one fan in service. Motor will be limited to high speed operation only with a maximum of 4000 HP. We estimated this option will increase auxiliary power use 10% because of losses associated with high speed operation. Increasing auxiliary power use increases the cost for this option $1,850,000. This cost was included in the installation and operating cost for comparison.

3. Rerate the motor to 5000/3200 HP 1.15 service factor per the analysis performed by Westinghouse. New motor rating is capable of providing unit operation at 500 MWg (60% maximum unit capacity). No changes are being made to the fan efficiency and consequently no changes to auxiliary power use during normal two fan operation.

4. Replace the motors with new two speed motors capable of 840 MWg with one fan in service at high speed. No changes are being made to fan efficiency and consequently no changes to auxiliary power use during normal two fan operation.

5. Install variable frequency drives and new motors. Equipment costs exceed assumed outage costs and auxiliary power savings were not considered.

ECONOMIC EVALUATION

<u>ASSUMPTIONS</u>

1. Cost of money is 8 percent, extra cost of one unit lost IGS generation is $10,000 per unit, per hour.

2. Motor failures associated with windings and/or rotors would require 4 weeks to repair. PA Fan motor failures would result in a unit trip with a minimum of two hours to return the unit to the full capability of unit operation with a single fan.

3. Failures associated with the bearings would require 8 hours for replacement. Failures would progress slowly enough to schedule the unit off line for repairs.

4. Net output factor for each unit is 90% During reductions in unit capability the other unit would be loaded to maximum capacity.

5. There will be at least one motor failure and a bearing failure during the remaining life of the motors. Motor life is assumed to match the useful life of the plant.

Based on our evaluation the cost for each option are broken down as follows: (Costs for motor repair are assumed to be equal for all options.)

OPTION	Description	Outage Cost	Installation & Operation	Total
1	Existing Oper.	$3,031,429	$ None	$3,031,429
2	New Wheels	$1,412,381	$2,624,512	$4,036,893
3	Rerate Motor	$1,412,381	$ 1,800	$1,414,118
4	New Motor	$ 0	$2,134,000	$2,134,000
5	New Drives	$ 0	>$2,400,000	>$2,400,000

We recommend increasing the rating on the PA fan motors in accordance with the computer analysis performed by Westinghouse. This recommendation is the most cost effective way to minimize outage costs associated with PA fan failures.

We have reviewed the existing electrical system with Black & Veatch (Appendix I-Black and Veatch report dated June 2, 1992) to determine the system capability to support to the proposed horsepower revisions to the PA fan motors. The existing power cables and switchgear cubicles are adequately sized to handle the proposed increase. The new high speed 1.15 service factor rating of 437 amperes exceeds the speed changer switch nominal nameplate rating of 400 amperes continuous by 9.25% However, the switch manufacturer, Esco has stated the switch can be operated at 440 amperes on a continuous basis with a slight increase in switch losses. The protective relays settings will have to be changed to accommodate the horsepower revisions.

Black and Veatch has also reviewed the increased loading on the foundations associated with the proposed horsepower revisions. The existing foundations are adequate for these changes.

The alarm limits on the stator winding temperature RTDs should remain the same to provide warning of thermal degradation of the motor insulation. The alarm limits on the motor cooling air filters should be revised to match existing site conditions. The alarm limits on the motor current will be changed to the new horsepower ratings. The Fox 1A will be set to give a warning alarm at 265 amperes low speed and 380 amperes high speed. The absolute alarm will be 304/437 to match the service factor ratings.

The motor ratings should be changed even if it is assumed there will not be any motor or fan failures which lead to a unit derate. The new ratings provide a greater capability for the PA Fans to respond to disturbances without affecting the life of the motors.

ALSTOM

Power
Customer Service

Intermountain Power Service Corp.
850 W. Brush Wellman Road
Delta, Utah 84624-9546

Attention: Mr. Jon P. Christensen, P.E.

Subject: Generator Study

Dear Mr. Christensen:

The Customer Service Division of ALSTOM Power Inc. is please to offer you the electrical Study defined below for your consideration.

ALSTOM is a leading company in the design, manufacture, commissioning and servicing of Turbogenerators within the range from 20 to 1500 MW.
The Company expertise extends to the upgrade or retrofit of Turbogenerators aiming for a life extension, power output increase and improved Reliability, Availability and Maintainability on both own and third party fleets.

Generator Temperature Study:

The following scope of work is included:

- Site visit (if possible) to look at the stator water system, hydrogen cooling system and excitation system and appreciate the potential upgrade or replacement
- Calculations using ALSTOM Computer Aided Engineering Tools to simulate today's operating thermal condition of the generator and determine any potential increase of its maximum capability
- Solutions to improve the generator thermal operating conditions by changing components on the stator water system and hydrogen cooling system or by replacing the winding by one made of a different technology
- Solutions to improve or replace the existing excitation system

ALSTOM

Power
Customer Service

Note 1:
The analysis will be more accurate if ALSTOM receives

- the attached questionnaire filled-in as exhaustive as possible,
- 2 precise records of all measurable parameters of the generator when operating on 2 different steady state loads,
- dimensional drawings of the hydrogen cooled bushing terminals
- answers to additional questions which may arise in the course of the study

Note 2:
Any opportunity to access one generator for measurements should be seized.

Typical Deliverables:

The following typical deliverables are proposed:

- A technical report including an active & reactive capability diagram showing the maximum capability and limiting parameters
- A report describing the proposed modifications to the stator water system and hydrogen cooling system, also including a budgetary price for engineering, material, site installation and associated planning
- A report describing the proposed new stator winding based on stainless steel hollow conductors and welded water boxes also including a budgetary price for engineering, material, site installation and associated planning
- A report describing the proposed modifications to the excitation system also including a budgetary price for engineering, material, site installation and associated planning

Clarification:

The electrical balance of plant downstream the generator is excluded from the study.

ALSTOM Power Inc.
5309 Commonwealth Center Parkway
Midlothian, VA 23112
Tel: 1-804-763-3124
Fax: 1-804-763-3120
john.archambault@power.alstom.com
Web site: http://www.alstom.com

ALSTOM

Power
Customer Service

Typical time frame for the study:

Week 1:

- **Preparation**

Week 2:

- **Site visit**

Week 3:

- **Computation of the generator as it operates today**
- **Determination of the maximum active & reactive and the limiting parameters**

Week 4:

- **Definition of the possible modifications to the stator water system and hydrogen cooling system**
- **Definition of the new stator winding and potential winding losses reduction**
- **Definition of the possible modifications to the excitation system**

Week 5:

- **Fine tuning of the reports**
- **Preparation of the budget prices and associated planning**

Information Required

- **Attached please find a questionnaire containing the required information to perform the study.**

Price

Price for Study $79,000

ALSTOM Power Inc.
5309 Commonwealth Center Parkway
Midlothian, VA 23112
Tel: 1-804-763-3124
Fax: 1-804-763-3120
john.archambault@power.alstom.com
Web site: http://www.alstom.com

ALSTOM

Power
Customer Service

The price is valid for 30 days and is payable 20% with order and 80% with submittal of the report.

Terms & Conditions

The Terms and Conditions are per the attached ALSTOM Services USERV00.

If you have any questions concerning this offer please do not hesitate to call me at 804-763-3124 or Mr. Alfred Laforet at 804-763-2034.

Sincerely,

John T. Archambault

ALSTOM Power Inc.
5309 Commonwealth Center Parkway
Midlothian, VA 23112
Tel: 1-804-763-3124
Fax: 1-804-763-3120
john.archambault@power.alstom.com
Web site: http://www.alstom.com

Generator (Part of) Retrofit - Input data to run CAE calculation
*) when filling in, precise the units in which the values are given

Name Plate	units	
MW output	MW	
MVA output	MVA	
Voltage	kV	
Power factor		
Frequency	Hz	
Speed	rpm	
H2 pressure	*	
Standard	IEC / ANSI	
Type of excitation	static	
	brushless	
	other ?	
Excitation voltage	Volt	
Excitation current	Amp	
Year of manufact.		
OEM		

Cooling system		
Stator winding		
Heat transfer	direct	
	indirect	
Primary coolant	hydrogen	
	water	
	air	
	other ?	
Stator core		
ventilation	radial	
	axial	
Primary coolant	hydrogen	
	water	
	air	
	other ?	
Rotor		
Vent. straight part	direct	
	indirect	
If direct,	axial	
	radial	
	axial & radial	
	pick-up	
	diagonal	
Subslot ?	yes / no	
Vent. end turns	direct	
	indirect	
If direct,	axial ducts	
	radial ducts	
Primary coolant	hydrogen	
	water	
	air	
	other ?	

Coolant (fluids)	units	
Water temperature	*	
Flow to gas coolers	*	
Flow to stator winding water coolers	*	
Flow to exciter coolers (if any)	*	
Lubricating oil temperature	*	
Flow to the generator bearings	*	
Flow to the hydrogen seals	*	

Curves (from O&M manuals)	
No load saturation curve	
Short-circuit saturation curve	

Drawings (from O&M manuals)	
Outline	
Sectional	
Winding scheme	
Cooling scheme	
Stator slot - cross section	
Rotor slot - cross section	

Recorded data (Control room)	units	
Active power	MW	
Reactive power	MVA	
Voltage	kV	
Power factor		
H2 pressure	*	
RTD between bars in the slots	*	
RTD cold gas	*	
RTD hot gas	*	
RTD in the stator core	*	
RTD on Teflon hose (outlet side)	*	
Field current	Amp	
Field voltage	Volt	

Stator core	units	
Core length	*	
core outer diameter	*	
core inner diameter	*	
ventilation ducts / tubes :		
number		
size	*	
breakdown		
Laminations :		
thickness	*	
Specific loss @ 1,5 T	*	
Stator slots :		
number		
total height	*	
width	*	
dovetail height	*	
tooth height above wedge	*	

Fan / Blower	units	
Number		
Gas flow	*	
Gas pressure	*	
Location		
Blades :		
number		
height	*	
outer diameter	*	

Shaft dimensions	units	
Material grade		
Bearing span	*	
Overall length	*	
Diameters :		
journals	*	
under end turns	*	

Rotor body	units	
Rotor body length	*	
Rotor body diameter	*	
Number of divisions		
Nb of poles	2 or 4 ?	
Nb of turns / pole		

Stator winding	units	
Parallel path per phase	0,2,3,4 ?	
Number of bars per slot		
Pitch	0 to ?	
Water flow for stator winding	*	
Water flow for terminals	*	
Endwinding angle (air gap bar)	°	
Endwinding angle (slot bottom bar)	°	
Axial distance between :		
winding ends and gas guide	*	
stator core and winding ends	*	
gas guide to end shield	*	
Water manifold location :		
inlet	DE / NDE ?	
outlet	DE / NDE ?	

Rotor winding	units	
Number of wounded slots		
Slot height	*	
Slot width on top	*	
Slot width at bottom	*	
Dovetail height	*	
Copper strip height	*	
Subslot :		
height	*	
width	*	
slope	*	
Damper circuit :		
Nb in pole face		
Which type in the slots ?		

Comments :

IP12_005099

Major Retrofit references (Third Party fleet) over last 5 years

ALSTOM

Plant / Component / Output / Country	OEM
• PARADISE / Stator / 436 MVA / USA	GE
• POSSOM Pt / Stator / 980 MVA / USA	GE
• DEELY / Stator / 495 MVA / USA	WH
• HAZELWOOD / Stator & rotor / 250 MVA / Australia	Parsons
• ESKHOL / Rotor / 304 MVA / Israel	Parsons
• KOZINIECE / Stator & rotor / 235 MVA / Poland	Elektrosila
• BIG BROWN / Stator / 645 MVA / USA	WH
• MONTICELLO / Stator / 645 MVA / USA	WH

ALSTOM

ALSTOM Power Inc.
CUSTOMER SERVICES DIVISION
General Terms and Conditions of Sale for Service

1. GENERAL

1.1 ALSTOM Power Inc. ("ALSTOM") and Purchaser agree that the following terms and conditions ("Terms") shall govern Services which ALSTOM may from time to time furnish or agree to furnish to Purchaser in connection with equipment for generating electric power or otherwise. These Services may be performed either on or away from Purchaser's premises. Normally the Service will include only technical guidance and consulting assistance. In some cases, Service may include the actual execution of activities such as warranty work, inspection and technical investigations, operational and maintenance checks, overhaul, maintenance and repair, testing and commissioning, and activities as agreed. Should either party in the future desire that some or all Services be governed by terms and conditions different from or additional to those herein then:

(a) such party may give notice to the other terminating the effectiveness of these Terms as to Services ordered or agreed to thirty (30) days or more after the date notice is given; or

(b) both parties may agree that different or additional terms shall govern the furnishing by ALSTOM of Services in any specific instance so long as the agreement is expressed in writing which is signed by both parties and which states that it takes precedence over these Terms.

1.2 These Terms, as supplemented by any special terms and conditions (including definition of scope of work) agreed in writing and signed by both parties, are intended to set forth the final, complete and exclusive statement of the terms of agreement between ALSTOM and Purchaser with respect to Services furnished by ALSTOM. The agreement of the parties with respect to these Terms and specific Services to be provided hereunder may not be amended or modified, nor may a provision thereof be waived, except in writing signed by the party or parties to be charged.

2. SCOPE OF SERVICES AND CHANGES

The Services to be furnished shall be as provided by separate written agreement in each case and ALSTOM shall not be responsible for performing work or Services except to the extent that they are specified in such an agreement. Purchaser shall have the right to request changes in the agreed Services. If such changes are acceptable, ALSTOM will prepare a written Change Order, to be signed by both parties before proceeding with the changes. Except as may be otherwise agreed to in writing, ALSTOM's scope of Services excludes all trade labor work and any supervision, management or regulation of Purchaser's personnel, agents or contractors and work related thereto, and it does not include responsibility for planning, scheduling, monitoring, or management of the work.

3. REQUEST FOR SERVICES

Unless an emergency need for Services arises making such notice impracticable, Purchaser shall give ALSTOM written notice reasonably in advance of the date on which ALSTOM personnel are requested to start performance of Services. ALSTOM shall promptly inform Purchaser whether the personnel will be available on that date, and if not, the nearest date on which they will be available.

4. PROVISION OF FACILITIES

Except as otherwise agreed in a specific instance, Purchaser shall be responsible for providing at its own expense all things necessary to enable ALSTOM personnel to perform field Services requested, including without limit personnel to operate the equipment in respect of which Services are being furnished; local labor and craftsmen including foreman and superintendents as required; lifting beams, slings, tools, craneage, scaffold, burning and welding equipment, instruments and other ancillary equipment required for all the Services; all lubricating oils, grease and fuels; all cleaning materials; adequate office, telephone and telex facilities; storage space for any special tools or equipment furnished by ALSTOM; all instruction manuals and drawings covering the equipment; first aid facilities; and all safety equipment and protective clothing equipment. Purchaser shall also be responsible for informing ALSTOM, prior to agreement on the price of Services, of any local permits or authorization which may be required for ALSTOM personnel to perform field Services.

5. REPAIR, OVERHAUL AND SPARE PARTS

5.1 Spare parts and other materials provided by ALSTOM as part of repair or overhaul work or other services shall be subject to ALSTOM's General Terms and Conditions of Sale for Equipment and Renewal Parts current at the time of purchase order. Purchaser is responsible for requesting and examining a copy of such terms and conditions.

5.2 Notwithstanding that Purchaser's equipment may be in the custody or control of ALSTOM in connection with the performance of repair or overhaul work or other services, risk of loss or of damage to such equipment shall remain with Purchaser at all times.

6. PAYMENT

6.1 Services will be paid for either on the basis of a lump sum price, if quoted, or on the basis of time and materials as set forth herein. The rates for ALSTOM personnel shall be as set forth in ALSTOM's Schedule of Rates for Field Engineers in effect at the time the Services are performed. The time charged to Purchaser for field Services will include lapsed time (based on an eight-hour shift per weekday) from the time of departure of the personnel to their return to headquarters. In the case of assignments requiring special preparation before departure or complementary follow-up work after return to headquarters (e.g. diagnostic test analysis, balancing analysis, instrument preparation) additional time will be charged. In such cases Purchaser will be notified prior to commencement of the Services.

6.2 A lump sum price, if quoted, and the Schedule of Rates, are based upon straight time for eight hours per weekday shift. If performance of the Services is delayed, interrupted, extended or accelerated by Purchaser or due to other causes beyond the reasonable control of ALSTOM, Purchaser shall pay ALSTOM additional compensation therefore in accordance with the then current Schedule of Rates, including any overtime premium.

6.3 Purchaser, as set forth in the Schedule of Rates, shall reimburse ALSTOM for all reasonable transportation, living and other expenses incurred for ALSTOM personnel in connection with field Services from the time of departure until return to headquarters. Such expenses shall include but are not limited to air travel, ground transportation, lodging, food, gratuities, etc. By prior agreement with ALSTOM, Purchaser may discharge any of its obligations under this Paragraph 6.3 to the extent that Purchaser provides at its own expense any comparable Services or facilities, the cost of which would otherwise have been reimbursed pursuant to the foregoing.

6.4 Neither the lump-sum price (if quoted) nor the rates in the Schedule of Rates include any Federal, state or local property, license, privilege, sales, service, use, excise, gross receipts or other like taxes which may now or hereafter be applicable to, measured by or imposed upon or with respect to the furnishing of the Services. Purchaser agrees to pay or reimburse ALSTOM, its subcontractors or suppliers for any such taxes which ALSTOM, its subcontractors or suppliers are required to pay or collect or which are required to be withheld by Purchaser.

6.5 Payments required under this Paragraph 6 shall be made within thirty (30) days after receipt of invoice, in United States dollars by electronic fund transfer to the location shown on the ALSTOM invoice. Overdue payments are subject to a late charge equal to the lesser of 1.5% per month or the highest applicable rate allowed by law.

7. ALSTOM AND AFFILIATED COMPANIES

As used in these Terms the term (i) ALSTOM shall include its employees, officers, directors, subcontractors and vendors; and (ii) an "Affiliated Company" shall mean a company which directly or indirectly controls, or is controlled by or is under common control with ALSTOM, including without limit ALSTOM companies overseas, and includes their employees, officers, directors subcontractors and vendors. At its discretion, ALSTOM may utilize personnel who are employees of Affiliated Companies in the provision of Services hereunder, and may subcontract work to Affiliated Companies. Affiliated Companies shall not however be under legal obligation to Purchaser in connection with such Services, and Purchaser agrees that it will look solely to ALSTOM as the responsible party in connection with all Services to be furnished hereunder.

8. WARRANTY AND LIMITATIONS THEREON

8.1 ALSTOM warrants to Purchaser that Services will be performed in a workmanlike manner and that recommendations for corrective action made in connection with technical investigations or inspections or the like will be based on its best judgment in light of the facts then known. Should any failure to conform with this warranty appear within one year from the date of completion of the Services and if promptly notified thereof in writing, ALSTOM will, at its option, either provide conforming Services without further charge or refund to Purchaser the amount Purchaser has paid in respect of non conforming Services.

8.2 THE FOREGOING WARRANTIES ARE EXCLUSIVE AND IN LIEU OF ALL OTHER WARRANTIES OF QUALITY, PERFORMANCE AND RESULTS, WHETHER WRITTEN, ORAL OR IMPLIED, AND ALL OTHER WARRANTIES INCLUDING ANY WARRANTY OF RESULTS, MERCHANTABILITY OR FITNESS FOR PURPOSE ARE HEREBY DISCLAIMED.

8.3 CORRECTIONS BY ALSTOM OF NONCONFORMITIES OR REFUND OF AMOUNTS PAID, IN THE MANNER AND FOR THE PERIOD OF TIME PROVIDED ABOVE, SHALL BE PURCHASER'S EXCLUSIVE REMEDY AND SHALL CONSTITUTE FULFILLMENT OF ALL LIABILITIES WITH RESPECT TO THE SERVICES RENDERED, WHETHER IN WARRANTY, CONTRACT, NEGLIGENCE, TORT, STRICT LIABILITY OR OTHERWISE, EXCEPT TO THE EXTENT PROHIBITED BY LAW. NEITHER ALSTOM NOR ANY AFFILIATED COMPANY SHALL UNDER ANY CIRCUMSTANCES BE LIABLE FOR LOSS OF USE OR FOR ANY INDIRECT INCIDENTAL OR CONSEQUENTIAL DAMAGES

9. INDEMNITY AND INSURANCE

9.1 ALSTOM will indemnify and hold Purchaser harmless from and against claims of third parties (including court costs and legal expenses incurred in defense thereof) for personal injury, death or damage to third party personal tangible property suffered in connection with activities of ALSTOM personnel while on or about Purchaser's premises, if and to the extent such damage, injury or death is caused directly and solely by the intentional acts or negligence of ALSTOM. The obligation of ALSTOM to indemnify Purchaser is conditioned on Purchaser's giving ALSTOM prompt notice of any loss, damage or claim, and providing ALSTOM a full opportunity to participate in the defense and to approve any settlement thereof.

9.2 ALSTOM shall, if requested by Purchaser, furnish to Purchaser a certificate of insurance coverage showing the existence and policy limits of ALSTOM of the following types of insurance or their equivalent: Comprehensive Automobile Liability; Workmen's Compensation and Employer's Liability.

9.3 Except as otherwise stated in Paragraph 9.1, ALSTOM shall not be liable for, and Purchaser shall indemnify and hold ALSTOM harmless from and against claims for personal injuries or death suffered by Purchaser's officers, employees or invitees and arising out of or in connection with performance or Services by ALSTOM on Purchaser's premises.

9.4 Without limiting the foregoing in no event shall ALSTOM be liable for any loss or injury (including death) to persons or property caused by:

(a) the negligence or fault of Purchaser, his employees, contractors, subcontractors or agents;

(b) failure by Purchaser, his employees, contractors, sub-contractors or agents to accept and implement advice given by ALSTOM;

(c) failure or malfunctioning of tools, equipment, facilities or devices provided by someone other than ALSTOM; or

(d) use of instruments and of the making of adjustments by Purchaser, his employees, contractors, subcontractors or agents, contrary to the advice or otherwise without the agreement to or knowledge of ALSTOM.

10. LIMITATION OF LIABILITY AND DISCLAIMER OF DAMAGES

10.1 The total liability of ALSTOM (whether under a theory of negligence, tort, professional or strict liability, contribution, breach of contract or warranty, or otherwise) arising out of or in connection with the provision of Services shall be limited to the greater of $50,000 or the price paid or payable to ALSTOM therefore.

10.2 NEITHER ALSTOM NOR ANY AFFILIATED COMPANY SHALL UNDER ANY CIRCUMSTANCES BE LIABLE FOR SPECIAL, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES WHETHER IN OR ON ACCOUNT OF CONTRACT, TORT, NEGLIGENCE, STRICT LIABILITY, PROFESSIONAL LIABILITY, CONTRIBUTION, FAILURE OF REMEDY OR OTHERWISE INCLUDING BUT NOT LIMITED TO DAMAGES FOR LOSS OF PROFITS OR REVENUE, LOSS OF USE OF ANY EQUIPMENT OR TECHNOLOGY, DAMAGE TO OTHER TANGIBLE PROPERTY OF PURCHASER, COST OF CAPITAL, COST OF SUBSTITUTE POWER OR EQUIPMENT OR SERVICES, DOWNTIME COSTS, DELAYS OR CLAIMS OF CUSTOMERS OR THIRD PARTIES FOR SUCH OR OTHER DAMAGES.

11. FORCE MAJEURE

ALSTOM shall not be liable for nor deemed to be in default on account of delays due to causes beyond its reasonable control. In the event of such a delay, the period of performance and the contract price will be adjusted as may be reasonably necessary to compensate ALSTOM for such delay.

12. PARTIAL INVALIDITY

If any provision shall for any reason be held invalid or unenforce-able, such invalidity or unenforceability shall not affect any other provision hereof, but these conditions shall be construed as if such invalid or unenforceable provisions had never been contained herein.

13. INDEPENDENT CONTRACTOR

In furnishing any Services for Purchaser, ALSTOM is acting as an independent contractor on its own behalf and not as an employee, agent or other representative of Purchaser.

14. PRE-EXISTING SITE CONDITIONS

It is understood and agreed by the parties that nothing herein shall be interpreted as placing any responsibility or liability on ALSTOM or Affiliated Companies for pre-existing site conditions, including but not limited to pollution, contamination, hazardous waste or toxic material; or for the generation, emission, or disposal of such substances. Purchaser shall protect and indemnify ALSTOM and Affiliated Companies against any and all claims or liabilities based on such pre-existing conditions.

15. CHOICE OF LAW

The construction and performance of this agreement and the rights and remedies of the parties hereof shall be governed by the law of the State of Virginia.

END

From: <alfred.laforet@power.alstom.com>
To: "Jon Christensen" <JON-C@ipsc.com>
Date: 9/6/2001 10:15 PM
Subject: Re: Generator Uprate Study for Intermountain Power
Attachments: HASTUTOP_Conditionbasedmaintenance.pdf; E610413a.pdf; Chan003-2.mpg; Tape001.mpg

Jon,

we did some preliminary calculations on your generator.

We do have some additional questions/information requests to fine tune and verify some of our assumptions.
Please let us know if you can provide any of the below.

1) confirm that the connection rings (phase rings) and terminals (bushings) are currently cooled separately from the stator bars (that is to say by a parallel circuit) .

2) confirm that the water flow of 391gal/min indicated in the maintenance manual corresponds to the total flow at the inlet of the machine (that is to say bars + connection rings)

3) Would it be possible to receive a record of the generator operation at full (or near) load with :
- electrical parameters (MW , P.F. , kV , A , excitation current and voltage)
- deionized water inlet and outlet temperatures (global , stator bars , connections)
- deionized water flows and for which circuits (bars only ? connections only ? bars + connection ? flow in the deionizer included or not ?)
- pressure drops through the stator winding

4) Is a rotor temperature measurement available (with the associated excitation current and Hydrogen pressure) ?

5) Is the number of stator vent ducts and of which size available.
(this can be reconstructed by measuring of a spare stator slot wedge and number of wedges)

6) Is any technical information about the bushings available (maximum current ? temperature measurements ? documentation from the supplier ? outline drawing ?)

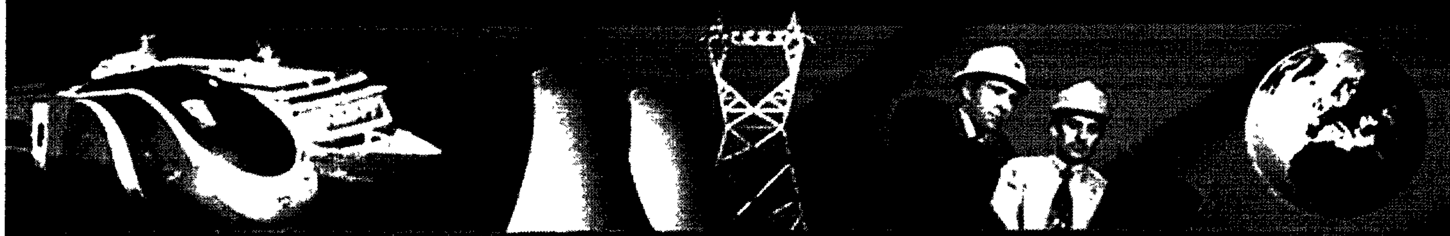
Attached you will find some info about our DIRIS system (robot) for testing with rotor in situ.

(See attached file: HASTUTOP_Conditionbasedmaintenance.pdf)(See attached file: E610413a.pdf)(See attached file: Chan003-2.mpg)(See attached file: Tape001.mpg)

I will send you some information about our new large generators.

Regards

Alfred



April 2001

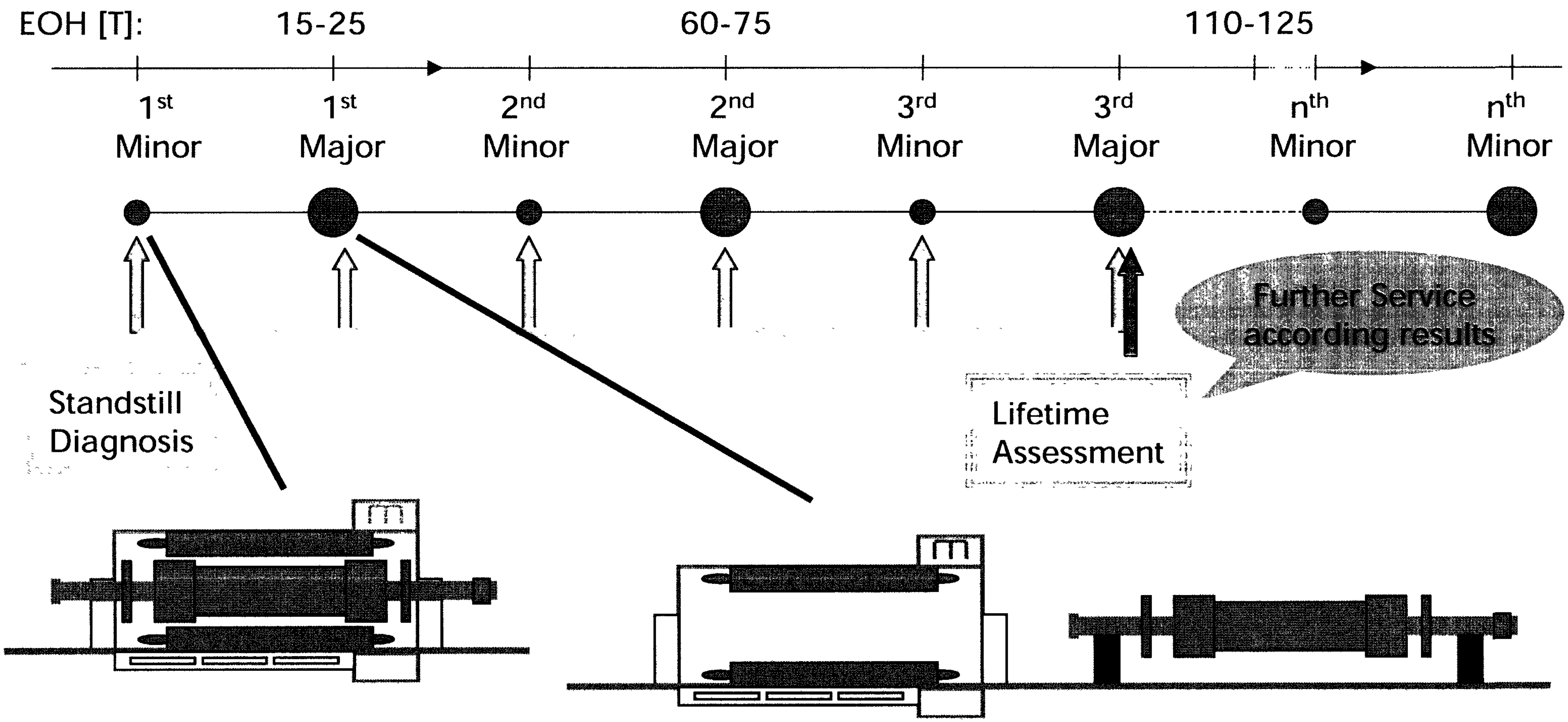
Condition based maintenance on generators supported with robotic inspections without dismantling the rotor

CSXC4

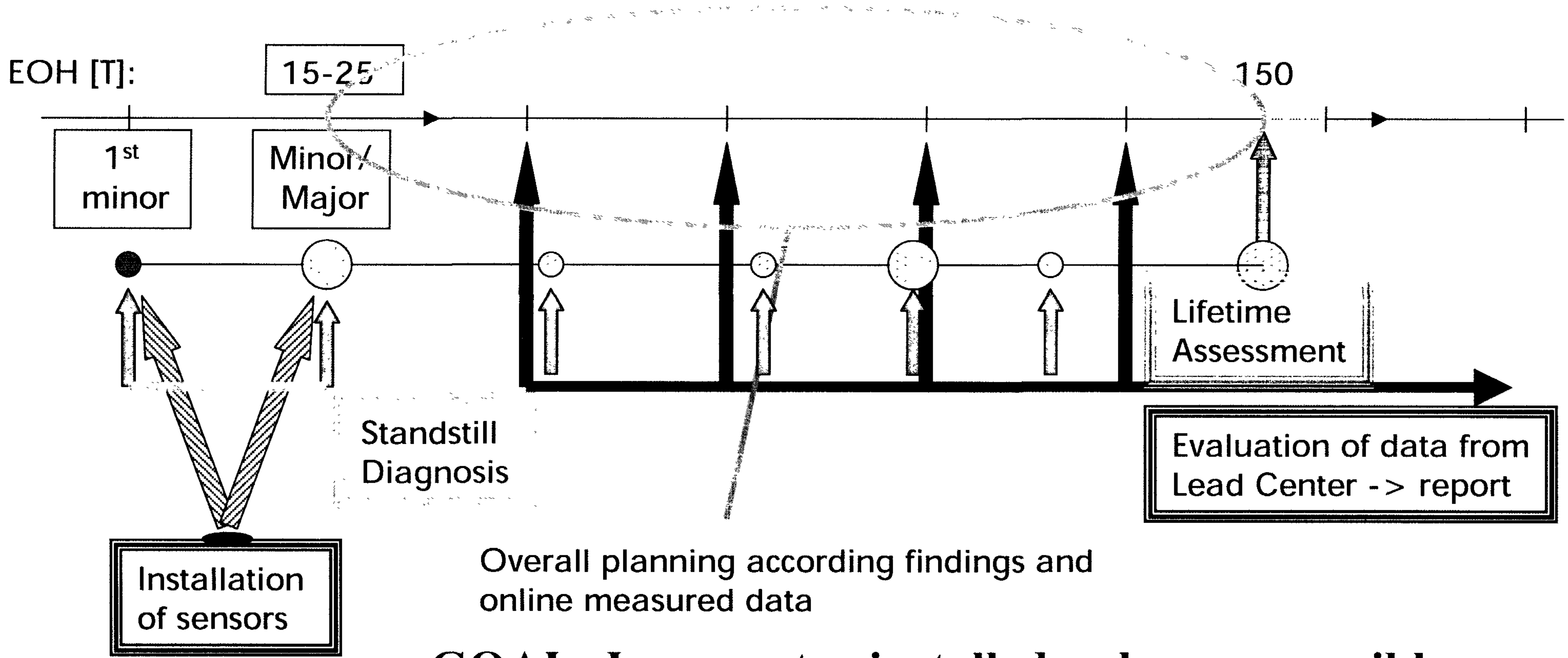
ALSTOM

Service Concept - Time Based

ALST M



Service Concept - Condition Based



GOAL: Leave rotor installed as long as possible
→ Condition based service concept

Service Concept - Condition Based

ALST M

To remove the rotor means

- High expenses in single shaft arrangement
- Risk of erection damages, alignment problems
- Rotor removed, but no major work needs to be done

→ Reduce Risks

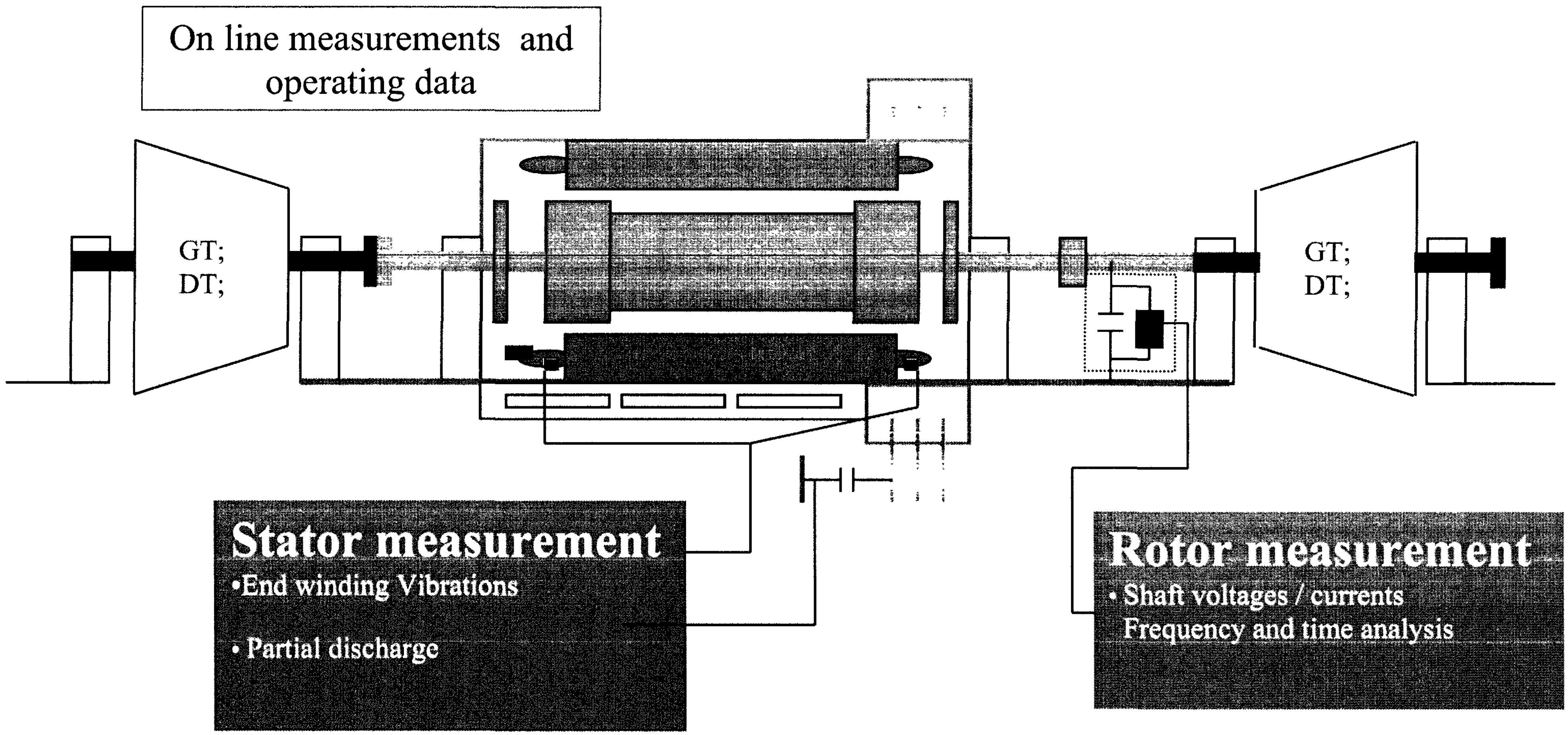
→ Save Money

→ Decisions for maintenance work based on...

→ Generator assessment

Generator assessment based on...

ALST M

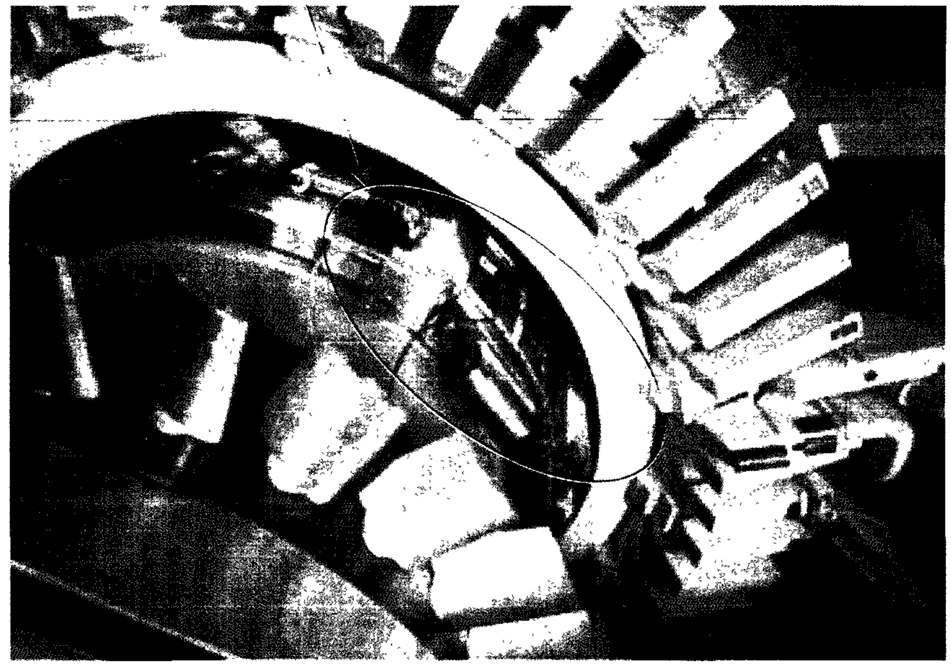


Generator assessment based on...

ALST M

Off line measurements
rotor installed

'Robot TOP' installed on retaining ring



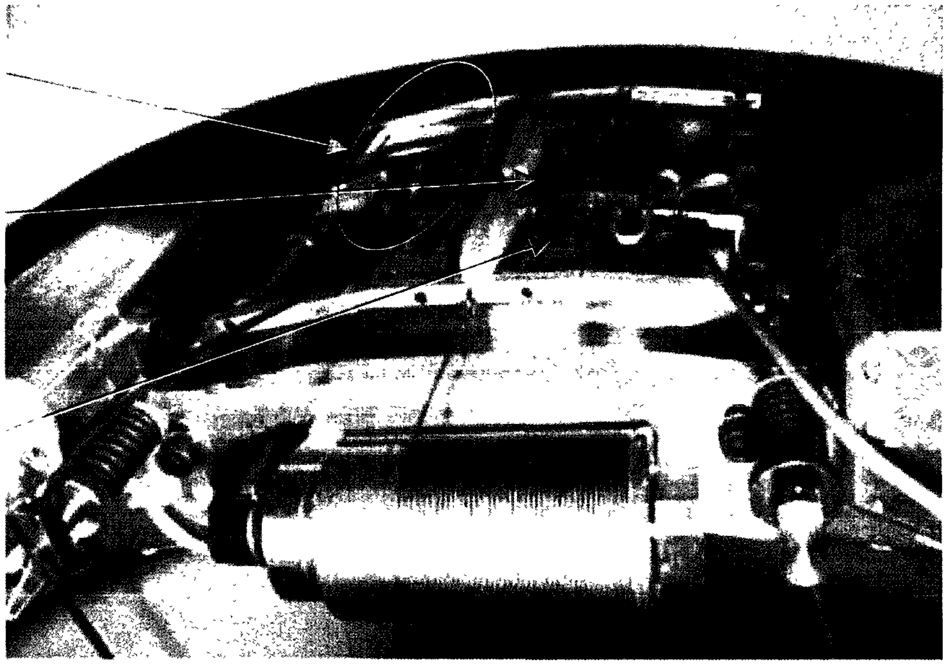
- 'Robot TOP' allows
  - -Visual Inspection
  - -Slot wedge tightness test
  - -Low flux for stator core assessment
- DC High Voltage measurements

'Robot TOP'

ALST M

Example: Probe for low flux stator core assessment combined with visual inspection, height < 20mm

- Microcamera with computer controlled inspection mirror
- Low flux probe for stator core assessment
- Magnets to hold robot on stator teeth

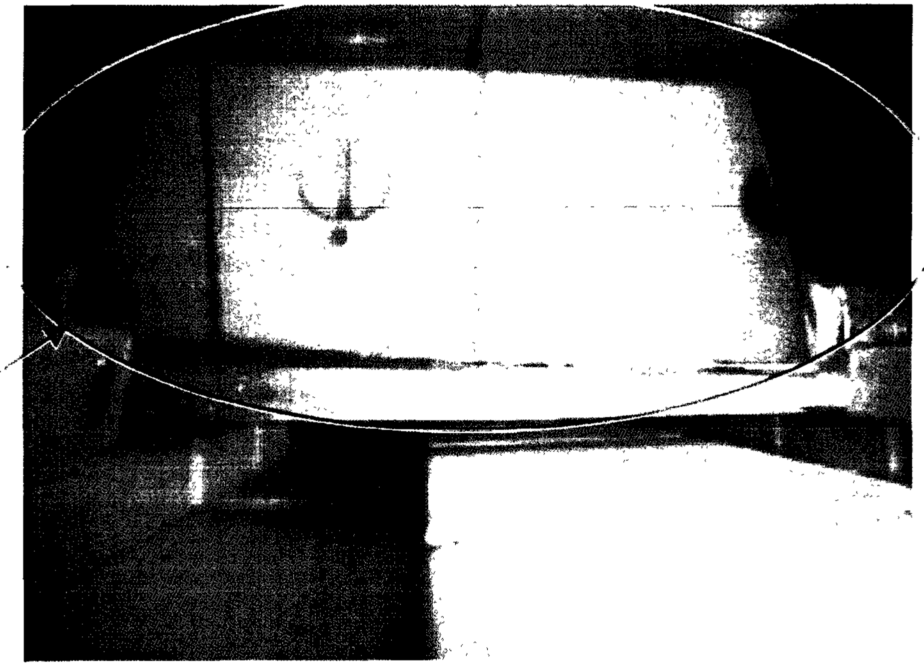


Visual Inspection Rotor installed

ALST M

Rotor surface

- Slot inspection
- Changing a slot
- Foreign particles



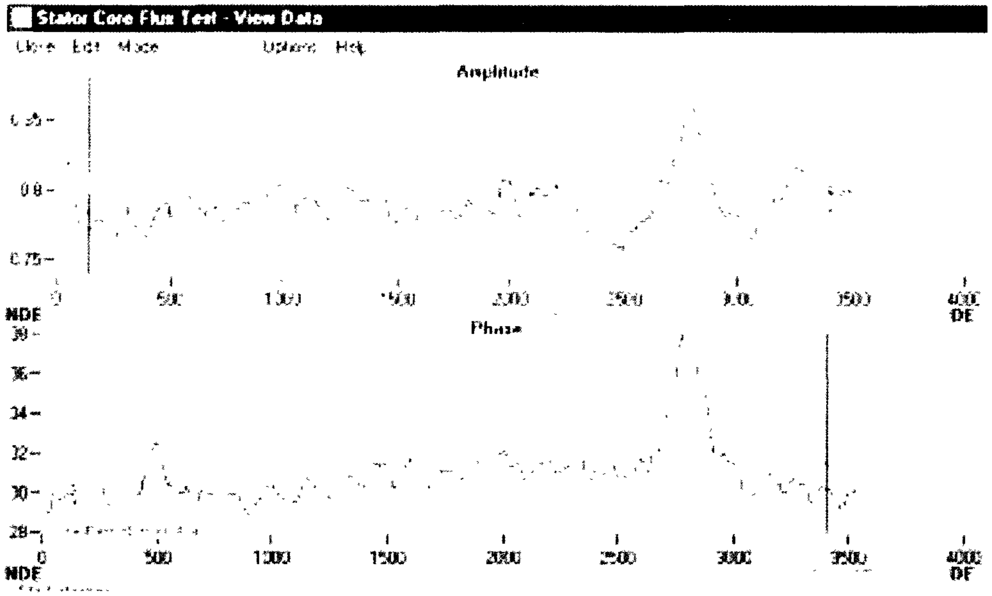
Mirror

Stator surface

→ Foreign particles eventually removed
→ Visual assessment of critical elements
→ maintenance work planned

Low flux stator core assessment

ALST M



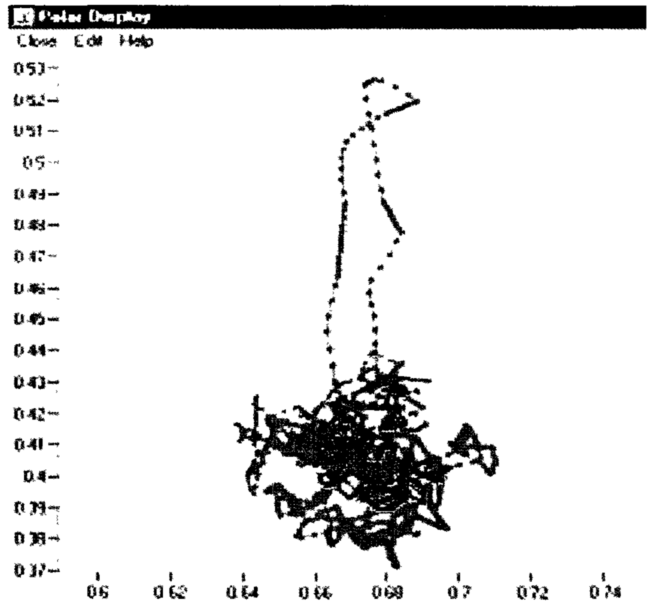
- Early detection of interlamination faults
- Very high reliability - all faults detected,accurately quantified according maximum power dissipation
- High repeatability allows trend monitoring and supervision of potential hazard spots

Phase and amplitude of flux signal measured

Polar plot allows clear identification of faults

Maximum possible fault Power calculated

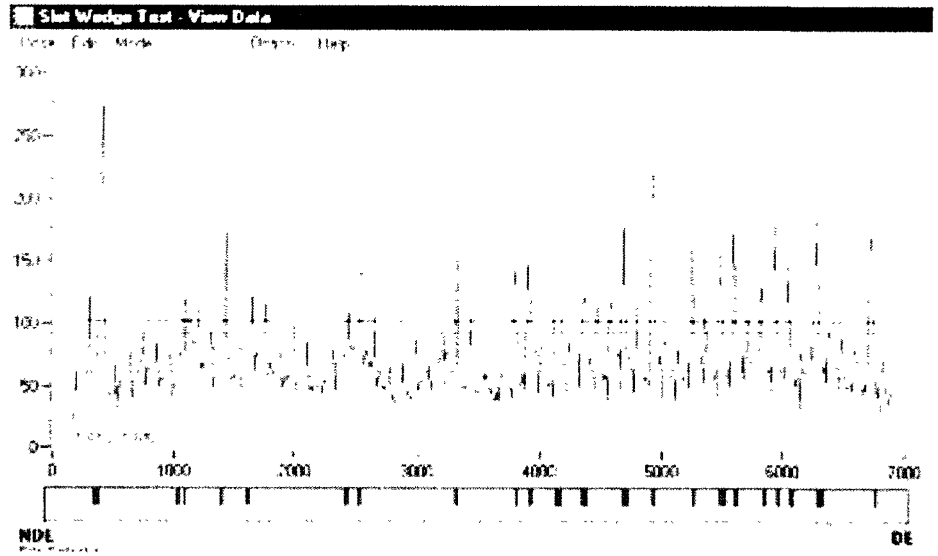
- maintenance work planned

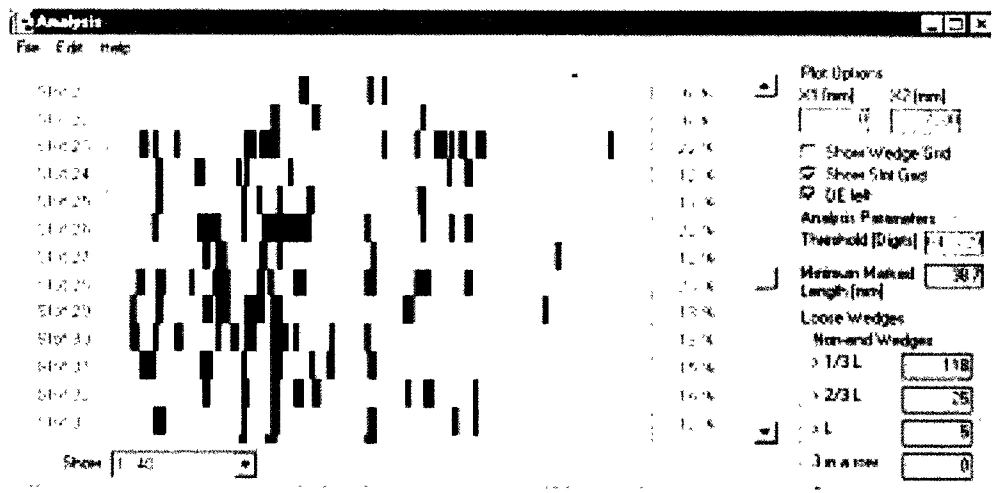


DIRIS Wedge tightness measurement ALST M

- Automatic control with acceleration measurement of wedge
- Automatic statistical analysis of complete machine

- Trend of wedge tightness over years allows maintenance planning





Combination of online data and diagnosis measurements allow comprehensive generator assessment with installed rotor

ALSTOM has the experience and the diagnosis tools

ALSTOM

www.alstom.com

IP12_005116

CSXC4		A, 2001-3-1	E610413a.doc
Z. Posedel	I. Kirchhoff	B. Mark	en 1/8
CS			1AHX

Revision

CSX Document Database

Document Type :	0717 Publications
Product Range:	0004 Generators
Product:	0001 General
Scope of Application:	0007 Service
Name of Plant:	General

Remaining to MSP:

Inspection of Stator Cores in Large Machines with a Low Yoke Induction Method- Measurement and Analysis of Interlamination Short-Circuits.

Z. Posedel
ALSTOM's Power

ABSTRACT

Interlamination short-circuits can cause major damage to electrical machines. Especially endangered are large turbo-machines with high yoke width and correspondingly high interlamination voltages. These generate during operation, at certain interlamination short-circuit contact resistance's, high short-circuit currents and lead in the worst case to "core melting". Generally the stator core for interlamination short-circuits is inspected under application of the high induction method, which often cannot give a satisfactory report on the lamination insulation condition. In particular the large magnetizing expense of the stator core (large voltage and current values of the magnetizing cable, availability of a strong current source) has proved to be disadvantageous. Furthermore, this method permits only a localization of hot spots on the surface of the tooth in the case of an assembled stator winding. All other interlamination short-circuits, especially far more dangerous ones in the slot wall or on the slot bottom respectively, are not accessible with this inspection. Also the interlamination short circuit with low contact resistance generated at the contact point little heat and therewith the low temperature. For these reasons, there is a need to develop a safe measuring method, which enables on one hand all interlamination short-circuits to be registered, and on the other hand a quantitative assessment of the danger of the interlamination short-circuits for the machine.

For nearly 20 years a measuring method with lower yoke-induction has been used without disadvantages of the high induction method. By this method an interlamination short-circuit is detected with a measuring coil. The signal has been interpreted in terms of current. With this interpretation of the measuring signal it is not possible to take a meaningful consistent quantitative analysis of the interlamination short-circuit. For a correct analysis we introduce a calibration procedure and data processing algorithm. The method with introducing a calibration procedure permits a complete analysis of the lamination insulation, both quantitatively and qualitatively. The analysis of the measuring signal, the mechanism of "core melting" and the comparison of the measuring methods will be treated in detail in this article.

1. INTRODUCTION

In the case of an interlamination short-circuit, the lamination voltage is short-circuited between at least 2 laminations. Through the measurement of the core tooth leak field with introducing the calibration procedure it is possible to detect all interlamination short-circuits. At this interlamination short-circuit spot, an electrical contact power will arise, which heats up the defective spot. Under certain contact conditions, the power consumption at the defect spot can lead to a melting of this contact. Further spreading can cause "core melting" and correspondingly damage the machine severely. The measurement of the core tooth leak field enables the maximum possible contact power at the interlamination short-circuit spot to be determined. If the ascertained contact load exceeds a defined critical power; the faulty spot is considered as a dangerous interlamination short-circuits. The critical power is defined as the lowest limit where "core melting" could arise. This critical power was determined theoretically as well as in trials. The interlamination isolation defects in the core end packets caused from the axial machine field can be also well detected.

With the help of the calibration procedure, the following is possible:

-Recording of the entire core tooth leak field over the stator teeth ("fingerprints").

-The recorded data serve for qualitative assessment of the design configuration of the stator and for a trend analysis.

-Recognition of all interlamination short-circuits by the determination of characteristic data (amplitude, phase angle).

-Localization of dangerous interlamination short-circuit spots by the determination of characteristic data (size, contact power, field gradient and position).

-Inspection of the interlamination short-circuits at generators with assembled rotor.

-Quick repair of the iron core with continuous checking of the repair steps.

2. STATOR INTERLAMINATION SHORT-CIRCUIT DETECTION WITH LOW INDUCTION METHOD

2.1. Magnetizing

The iron core is weakly magnetized with a coil, which is placed around the stator core:

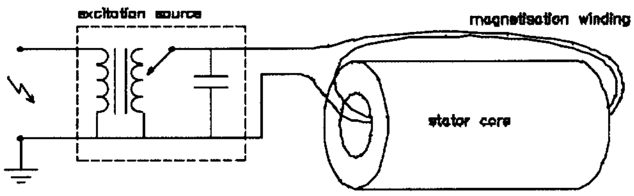


Figure 1. Stator core magnetizing with low induction

Because the yoke induction in this measurement is about 5% of the rated induction, the low voltage net is sufficient for feeding the induction coil. A variable transformer from the low voltage socket outlet (220/110 V, 50/60 Hz) performs the ring magnetization. Through compensation of the inductive reactive current by means of parallel connected capacitors, the feeding current can be reduced. The maximum feeding current will not exceed 20 A for this measurement.

The magnetization of the stator core in the case of machines with assembled rotor, especially in case of large turbo-machines, is preferably done with a low voltage source, which is connected between two machine sides to the shaft. The rotor must be completely insulated against earth on one side of the machine. Defective insulation on one side of the machine may be observed through measurement of the shaft current with a Rogowski coil and with the control of the shaft earth potential.

2.2. Analysis the measuring signal

In contrast to traditional iron core examination at rated induction, where hot interlamination short-circuits ("Hot spots") are registered (infra-red camera, hand checking), this method uses one or two coils assigned on the surface in order to determine the magnetic tooth leak field Φ_{str}. The measuring coil with the length l, the cross-section A and the number of winding w is mounted in the iron core between two teeth and moved along the slots.

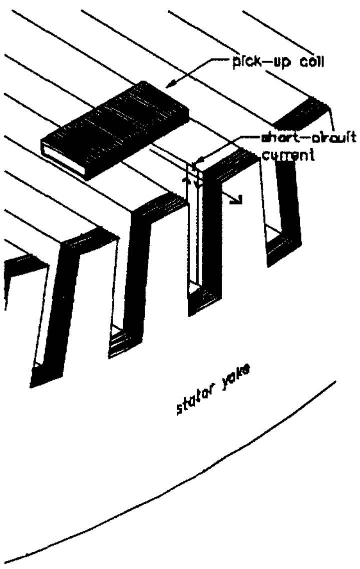


Figure 2. Tooth leak field detection with measuring coil

The induced voltage of the measuring coil if there are no interlamination short-circuits is:

$$u_M = \int_0^l \frac{\Phi_{Str}}{dt} \cdot \frac{w}{l} \cdot dl$$

With fulfilled the following conditions:

- Number of windings per length-unit

$$\frac{w}{l} = \text{const.}$$

- Coil cross-section along the measuring coil

$$A(l) = \text{const.}$$

- Total magnetic induction in the measuring coil.

$$B = \text{const.}$$

The constant value of the total magnetic induction does
not depend on the coil dimensions.

The induced measuring voltage can be further written as:

$$u_M = f(I_M)$$

In the measuring coil, in the absence of interlamination short-circuits, a voltage will be induced which is linearly dependent on the magnetizing current. As the magnetizing current does not have a sinusoidal shape (due to the hysteresis), the induced measuring voltage will not be a sinusoidal signal. The measured voltage U_M of the measuring coil, when the iron core is free of interlamination short-circuits, is proportional to the magnetic potential between the coil ends respectively to the magnetizing current. The measuring coil serves as a magnetic potential measuring device (Rogowski coil or Chattock potentiometer) of the linear integral between the end points of the measuring coil.

If there is an interlamination short-circuit, the fault current I_F will induce a voltage in the measuring coil:

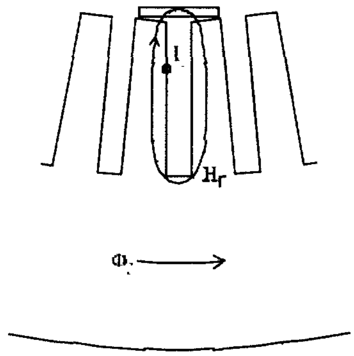


Figure 3. Leak field of the fault current

Because of the small interlamination short-circuit length, which is much smaller than the coil width, the total magnetic induction is dependent on the dimension of the coil.

$$B \neq \text{const.}$$

The measuring coil can not be interpreted as Chattock magnetic potentiometer for the interlamination short current as described in El Cid tests (1). The interlamination short-circuit current cannot be determined from the measured voltage. The interpretation of the measuring signal is a significant weakness in the El Cid test. Since a meaningful and consistent quantitative analysis of the measuring signals is not possible. The measurement signal is dependent on the fault current magnitude and the length of the interlamination fault.

Because of the small interlamination short-circuit length, which is much smaller than the coil width, the interlamination short-circuit current cannot be determined from the measured voltage. This is a significant lack of the El Cid tests (1). The measurement signal dependent from the product value of the fault current magnitude and the length of the interlamination fault. The measure voltage at different interlamination short-circuits can be see in the Fig.4.

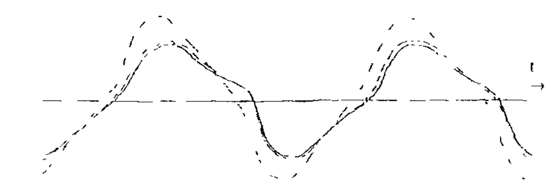


Figure 4. Time pattern of the measured voltage at different
interlamination short-circuits:
——— without interlamination short-circuits
------- with 5 mm interlamination short-circuits
-------- with 10 mm interlamination short-circuits

2. 3. The recognition of the interlamination short-circuits

An interlamination short-circuit is characterized by an increased phase angle and amplitude of the measured voltage (under the assumption that there is no effect of the interlamination short-circuit current to the magnetization in the yoke).

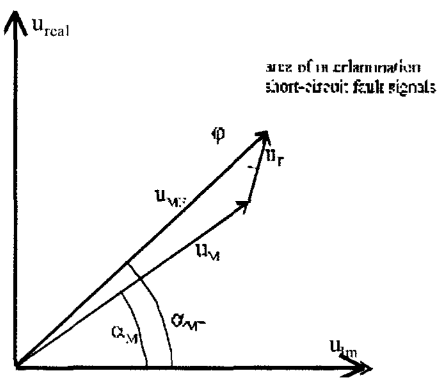


Figure 5. Vector diagram with unchanged yoke field

u_M = Measured voltage without fault

u_{MF} = Measured voltage with interlamination short-circuits

α_M = Phase angle without interlamination fault

α_{MF} = Phase angle with interlamination faults

φ = Phase angle of the fault current

$$\Delta u = u_M - u_{MF}$$

$$\Delta\alpha = \alpha_M - \alpha_{MF}$$

The phase and amplitude deviations Δα and Δu_M, caused by the lamination short-circuit currents, are registered over the slot length and stored in a computer. The measured phase angle signal is independent of the yoke induction in the range of a magnetic yoke induction between 0.003 T and 0.7 T. The measuring signal is fully reproducible and serves as a "fingerprint" of the stator core lamination state. The measurement is used for trend analysis.

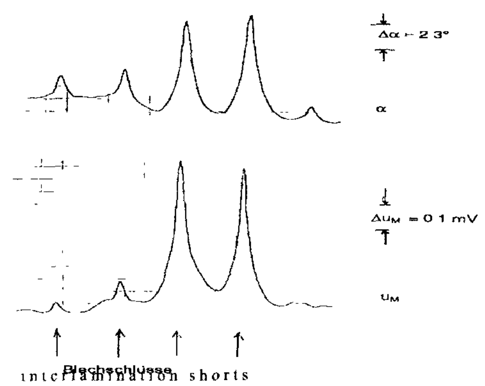


Figure 6. Amplitude and phase angle changes at interlamination short-circuits

Without an interlamination short-circuit, the voltage and phase angle of the measuring signal vary because of the varying magnetic potential in the circumferencial direction. This varying magnetic potential is characterized by reduced amplitude accompanied by increased phase angle of the measured voltage or vice-versa. The registered field patterns indicate the quality of the lamination insulation and the design symmetry of the lamination.

2.4. Evaluation of the measured data

The recorded values of the tooth leak field can only be evaluated through the calibration of the measuring coil. The measured signal change depends on the magnitude of the interlamination short-circuit current I_F and its length l_F:

$$\Delta u(\Delta\alpha) = f(I_F, l_F)$$

The data registered with the measuring probe along the slots are compared with the signals, which have been obtained from the calibration. A loop of a thin wire with the breadth of a few millimeters l_E is fixed on the tooth surface and fed with a calibration current I_E.

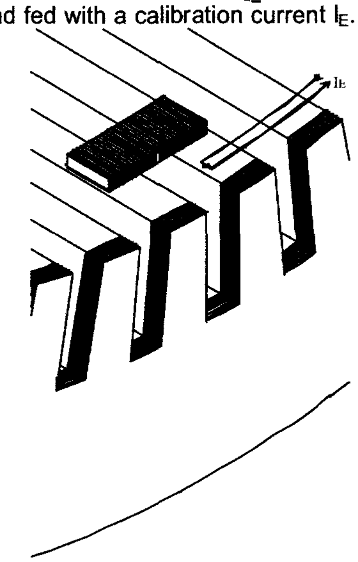


Figure 7. Calibration arrangement

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The difference of the measuring signal is registered with and without this loop current (α_E, α_M) and compared with the measured signal of the interlamination short-circuit current (α_{MF}, α_M).

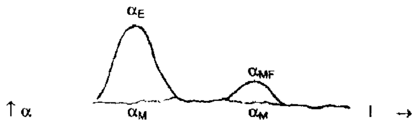

Figure 8. Measured signal change during calibration and interlamination short-circuit

From that follows the characteristic interlamination short-circuit magnitude $I_F \cdot l_F$ (Product of the interlamination short-circuit current and the interlamination short-circuit length):

$$I_F \cdot l_F = I_E \cdot l_E \cdot \frac{\alpha_{MF} - \alpha_M}{\alpha_E - \alpha_M}$$

Because for a fixed magnetic induction the voltage between laminations is constant in the core per unit length, the measuring signal can then be interpreted as power dissipation from an interlamination short circuit current.

$$\Delta u(\Delta\alpha) = f(I_F, l_F) = f(P_F)$$

This is the maximum possible power dissipation from an interlamination short circuit current. The power on the short circuit contact depends of the resistance's in the short-circuit path.

2.5. Interlamination short-circuit contact power

The interlamination short-circuit current of short-circuit circuited laminations is defined by the induced voltage between the two laminations and the resistance of the single laminations. Whether core melting caused by an interlamination short-circuit arises, depends not only on the interlamination short-circuit current, but also on the interlamination short-circuit resistance, the heat conduction, the heat dissipation and heat capacity of the contact spot. The maximum interlamination short-circuit contact power between two laminations occurs when the contact resistance R_K is equal to the lamination resistance's 2 R_B. The contact resistance between the back wedge and the laminations is assumed to be zero. Every lamination must be well grounded over the back wedge.

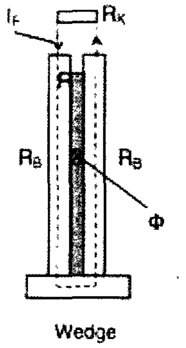

Figure 9. Two laminations model

P_K = Contact load
R_K = Contact resistance
R_B = Ohm resistance of a lamination
u_B = Voltage between 2 laminations
Φ = Magnetic flux between 2 laminations

The maximum current between two shorted laminations:

$$I_{max} = u_B/2R_B$$

The maximum power dissipation between two shorted laminations:

$$P_{max.} = u_B^2/8\ R_B$$

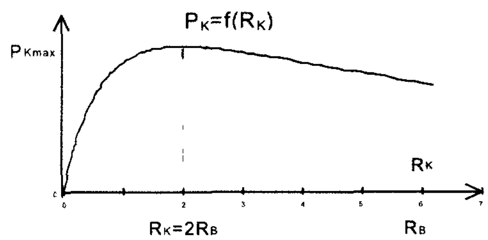

Figure 10. Interlamination short-circuit power curve

The lamination resistance of large machines is 5-10 mΩ. The maximum contact current between two 0.5 mm laminations is about 200 till 400 mA for large turbo-generators (by the measuring magnetic induction from 0.1 T with a lamination voltage of about 4mV. There is evidence that the limit value of 100 mA from the El Cid test is not correct. Also the limit current value of 100 mA can not be used for all machine. The same interlamination short current value is much less dangerous for hydromachines than for turbomachines.

The contact power of the interlamination short circuits for a correct analysis must be know. The maximum contact power between two 0.5 mm laminations is about 100 mW for large turbo-generators in operation (magnetic induction 1.5T with a lamination voltage of about 60 mV). As electrical machines have similar lamination quality and operating conditions, the electrical contact power is mainly given by the yoke height of the stator core. The frequency of the core melting, which is much higher for turbomachines, confirms this reflection.

2. 6. The limit power value of the interlamination short-circuit

The interlamination short-circuits between two laminations with contact thickness of less than 0.1 mm are quickly molten because of poor heat conduction and heat dissipation to the surroundings. In the case of short-circuits over many laminations (higher interlamination short-circuit load), contact melts can form and trigger core melting. A specification of the limit values for the maximum permissible interlamination short-circuit power is difficult because it is hard to predict how the lamination power will be turned into heat on the surface of the stator. The local heating of the core depends not only on the magnitude of the interlamination short-circuit power and the contact resistance, but also on the geometry of the interlamination short-circuit contact. In the case of more than two short-circuited laminations, the interlamination short-circuit power rises approximately as the square of the length and quickly reaches values which can be considered as dangerous for the safety of the machine. Trials and experience show that a maximum interlamination short-circuit power dissipation in operation of 15 W can represent a danger for machines. An interlamination short-circuit power dissipation of 15 W is treated as the lowest level which core melting can arise. This value should be assumed as the limit value. It is applicable to all machines.
With this assumed limit value at rated induction, the length of the short-circuited laminations, which can endanger the operational safety of the machine, would be:
4 - 10 mm for turbomachines
10 - 20 mm for hydromachines.

2.7. Field gradient measurement from an interlamination short-circuit

A further measurement, with two measuring coils arranged over each other on the iron stack surface, was often used to determine the field gradient in addition to the phase and the amplitude (3).

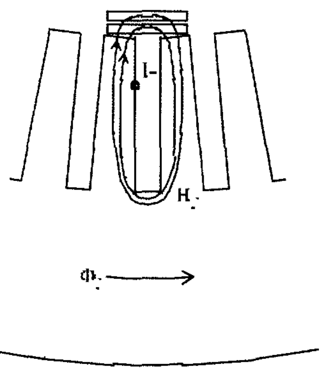

Figure 11. Iron laminations control with two measuring coils

The radial field distribution is strongly dependent on the location of the interlamination short-circuit. At an interlamination short-circuit, the fault current over the short-circuited laminations induces in the measuring coils different, phase-shifted voltages U_{M1} and U_{M2}.

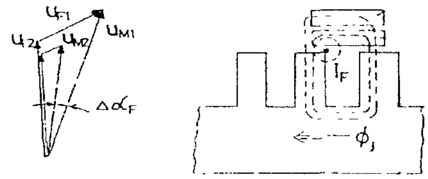

Figure 12.Vector diagram of the measured voltages at an interlamination short-circuit

The field gradient measurement therefore allows a localization of the interlamination short-circuit. Through comparing the radial field gradient of the calibration loop with the field gradient of the interlamination short circuit current it is possible to determine the fault location. The field gradient of an interlamination short-circuit on the surface is much more pronounced than an interlamination short-circuit in the slots.

3. COMPARISON OF THE MEASURING METHODS

There are two main stator core inspection methods:

-Infrared detection of hot spots on the stator surface at rated yoke induction
- Magnetic field measurement of the interlamination short-circuit current with low induction.

3.1. Infrared detection of hot spots on the stator surface at rated yoke induction

The first, very well known and often used, method at rated yoke induction for recognition of hot spots cannot give satisfactory results, because of the following disadvantages:
- In order to carry out the measurements, a high power supply source (single phase) is required, as well as extensive measuring equipment (long high-current and high-voltage cable, transformer etc.). The method is therefore very expensive and time-consuming.
- The method shows only hot spots and not all interlamination short-circuits; e.g. an interlamination short-circuit with a full contact ($R_K = 0$) will not have any losses at the interlamination. Short-circuit spots and therefore the interlamination short-circuits cannot be heated.
- On generators with assembled stator winding this method shows only visually accessible hot spots on the stator surface. The other interlamination short-circuits, which lie on the slot wall or on the slot bottom, cannot be seen but are even more dangerous.
- To use the temperature as a comparison value for the assessment of the lamination insulation quality is not

the best solution. Less dangerous are interlamination short-circuits between two laminations which can have very high temperatures, in comparison with larger interlamination short-circuits, which, at small contact resistance over many laminations show low values.
- The inspection of hot spots is very difficult in large turbo-generators because of a small-bore diameter and a large machine length.
- Lamination control during a repair of interlamination short-circuits requires a very long time. Every interlamination short-circuit can only be checked after a long cooling time of the iron core.

3.2. Magnetic field measurement of the interlamination short-circuit current with low induction

The low induction methods have several well-recognized advantages over the high induction method:
- The yoke magnetization is possible without large expenditure and the measuring instrument is simple.
- The measurement indicates all interlamination short-circuits, even those which lie in the slot wall or on the slot bottom.
- The control during a repair of the lamination is easy and can be carried out immediately.
- The measurement indicates all interlamination short-circuits, even those which are not hot.
- In the case of large turbo-machines, the measurement is possible with an assembled rotor.

There are two different measuring systems for the control of the stator core insulation with low yoke induction.

- The measuring signal has been interpreted in terms of current (1).

According to this measurement system, the measuring coil measures directly the interlamination short-circuits current during the examination of the lamination insulation (1). The measuring coil is considered to be a magnetic potentiometer. But since the interlamination short-circuit currents are mostly shorter than the breadth of the measuring coil, it is clear that the direct measurement of the interlamination short-circuit current is impossible. Mostly, in comparison with actual interlamination short-circuit currents, much smaller values are indicated. The measuring coil is, in fact, suitable for the detection of the interlamination short-circuits but not for their quantitative analysis.

- The analysis of the measuring signal with introducing a calibration procedure.

The magnetic field measurement of the interlamination short-circuit current with introducing a calibration procedure is characterized by the additional following advantages:
- A complete qualitative and quantitative assessment of interlamination short-circuits and precise evaluation of the measured results.
- The measured phase signal is independent of the yoke induction in the range of a magnetic yoke induction between 0.003 T and 0.7 T. The measuring signal is fully reproducible and serves as a "fingerprint" of the stator core lamination state. The measurement is used for trend analysis.
- The registered field patterns indicate the quality of the lamination insulation and the design symmetry of the lamination.
- Interlamination short-circuit power is determined and the dangerous spots are indicated. The interlamination short-circuit power is the most important value for the assessment of the danger of an interlamination short-circuit.
- Localization of the fault is possible using the double coil (measure the radial stray-field gradient.

4. CONCLUSION

Disadvantages of the classical measuring method of lamination insulation control with high yoke induction (high costs, inadequate detection of the interlamination short-circuits, unsatisfactory assessment criteria etc.) are avoided by the measurement of the tooth leak field at low yoke induction.
With this measurement, all interlamination short-circuits (hot or not) are detected. The measurement can be carried out with the assembled rotor. The measurement of the tooth leak field with the calibration procedure gives correct information about interlamination short-circuits. The reproducibility of the measured values is complete and the measured field pattern serves as a "fingerprint" of the stator core. With the calibration procedure and data processing algorithm, assessment criteria (power of the interlamination short-circuit spots) were determined. With the method suggested, the quality of inspection should be improved and the operational safety of the machine increased. This method with a meaningful and consistent analysis of the data and assessment criteria should be used as a standard control of the stator core by the acceptance tests.

5. LITERATURE

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[3] G.Biechl, K.Reichert, A.Huber, Z.Posedel, B.Wiederkehr, Supervision of Synchronous Generators: Condition Monitoring and Diagnosis, International Conference on the Evolution and Modern Aspects of Synchronous Machines, 27 - 29 August 1991 Swiss Federal Institute of Technology, Zurich, Switzerland.

Zlatimir Posedel received his Dipl. Ing. degree in Electrical Engineering from the University of Zagreb in 1958. From 1958 to 1963 he was a system planning engineer for Electrical Enterprises Zagreb, and an assistant professor at the University of Zagreb. Since 1963, he has worked with ASEA Brown Boveri, Baden, Switzerland as a development engineer. In 1972 he took part in a special Summer session program on superconducting machinery at MIT-Cambridge. He is the author of several technical papers and holds several patents. As co-author he received the IEEE Prize Paper Award 1991(New York) from the Electric Machinery Committee and the IEEE Paper Award 1991 (San Diego) from the Power Engineering Society.